Preliminary Staff Assessment

BLYTHE ENERGY PROJECT PHASE II

Application For Certification (02-AFC-1)
Riverside County

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STAFF REPORT

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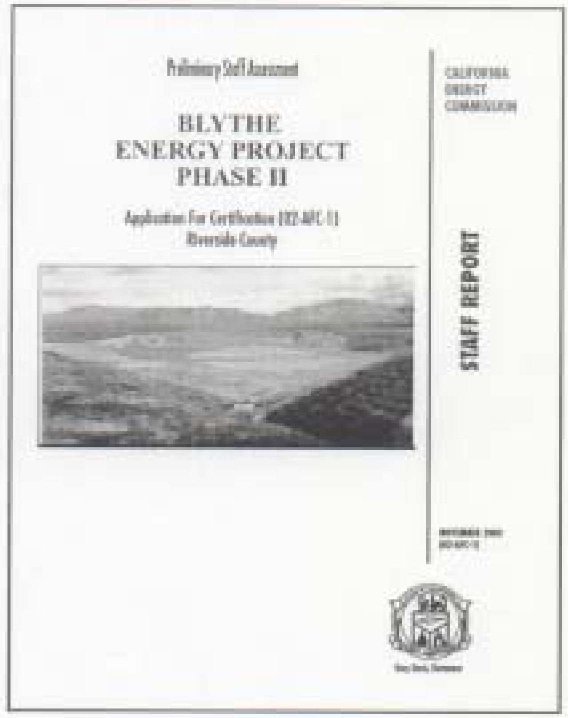
Gray Davis, Governor



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The Preliminary Staff Assessment (PSA) contains the California Energy Commission (Energy Commission) staff's independent evaluation of the Blythe Energy Project Phase II (BEP II) Application for Certification (AFC) (02-AFC-1). This PSA examines engineering, environmental and public health and safety aspects of BEP II, based on the information provided by the applicant (Caithness Blythe II, LLC) and other sources available at the time the PSA was prepared. With the exception of nine technical areas, it also includes conclusions, recommendations and proposed conditions of certification that would apply to the design, construction, operation, and closure of the proposed facility if it is certified. The PSA contains analyses similar to those contained in Environmental Impact Reports required by the California Environmental Quality Act (CEQA).

The PSA is not a Committee document nor is it a final staff recommendation or proposed decision on the proposal. After considering public and agency comments and the additional information identified in this document is received, a Final Staff Assessment (FSA) will be completed.

BACKGROUND

The BEP II AFC was filed with the California Energy Commission on February 19, 2002. The project AFC was amended in May to relocate the BEP II structures to the adjacent parcel and again in July of 2002 to reconfigure the evaporation ponds. On July 17, 2002, the Energy Commission found the AFC to be data adequate for the 12-month review process. The project is located adjacent to the Blythe Energy Project I (BEP I) that was approved by the Energy Commission on March 21, 2001. The applicant has identified the Western Area Power Administration (Western) as an interconnecting utility; however, a system impact/facility study of the project's transmission interconnection configuration(s) is still needed for staff to complete its evaluation.

In the past, where there has been an interconnection with Western, the Energy Commission and Western have completed a joint National Environmental Policy Act (NEPA) and CEQA study of the project. In this case, however, Caithness Blythe II has not funded Western's participation in the environmental review process and the necessary transmission interconnection studies. Therefore, the Energy Commission staff prepared this PSA as a CEQA equivalent document, independent of Western. If the project interconnects with Western at the Buck Blvd. substation, a NEPA process will be required.

The review of the BEP II AFC was delayed due to many unresolved issues, including transmission line configuration issues and the lack of completed interconnection studies by the interconnecting utilities (Western, Southern California Edison (SCE), and Imperial Irrigation District (IID)). There were also disagreements between staff and the applicant on the potential for impacts to the Colorado River groundwater and water conservation measures. Staff issued three rounds of data requests to the applicant, resulting in three volumes of data response comments. It should be noted that some of the data response comments have resulted in changes in the project description not reflected in the AFC or AFC amendments.

For example, the AFC provides a project description that does not accurately define how the power generated at the Blythe II project will be interconnected to downstream systems. In March 2003, the applicant issued Data Response 179a, citing the Blythe Area Regional Transmission Flow Analysis (BART Study) as a definition of how BEP II will interconnect with downstream systems. The BART Study analyzed the Blythe area's regional transmission system including the feasibility of selected transmission options to support the reliable interconnection of the 520 MW BEP II project. The study shows 8+ scenarios of transmission lines extending offsite from the Blythe II project. In a conference call on April 10, 2003, the applicant proposed an interconnection plan that would tie Blythe II to the Buck Boulevard Substation and a proposed IID 118-mile 230 kV or 500kV transmission line connection to the Devers Substation. Therefore, although it is not specifically contained in the AFC, this one BART Study alternative is the BEP II project description interconnection configuration Caithness is seeking a license for and is the project description staff assessed in this PSA.

The analyses contained in this PSA are based upon information from: 1) the AFC; 2) subsequent amendments; 3) responses to data requests, workshops and site visits; 4) supplementary information from federal, state and local agencies; 5) staff research; and 6) existing documents and publications.

PROJECT DESCRIPTION

BEP II is a nominally rated 520 MW combined-cycle power plant consisting of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTGs), one (1) 180 MW steam turbine generator, and supporting equipment. BEP II is adjacent to and located entirely within the approved BEP I site boundary on the Expansion Site approved by the Energy Commission as an amendment to BEP I (See BEP I Petition for Amendment I-B, dated November 23, 2001). BEP II may utilize some existing facilities at the BEP I site including the Control/Administration and Maintenance Buildings. Other BEP I facilities that are proposed to be expanded to serve BEP II include the groundwater supply, water treatment systems, fire protection facilities and site access roads. Natural gas will be supplied to the BEP II plant by the natural gas pipeline constructed as part of the approved and operating BEP I project.

BEP II will be electrically interconnected to the Buck Blvd. Substation, located at the northeastern corner of the BEP I site. Western constructed the Buck Blvd. Substation as part of BEP I, and currently owns and operates the facility. Some of the additional facilities required in the Buck Blvd. Substation for BEP II have already been evaluated and approved as part of the Western BEP I Facility Study. However, to facilitate the 500kV single circuit line from the new BEP II 500 kV Integration switchyard, the Buck Blvd. Substation would be expanded to include three new 500 kV switch bays and a new step-down transformer. A new 2,500 foot long 500 kV single circuit transmission line would connect the BEP II 500 kV Integration switchyard to one of the proposed 500 kV switch bays in the Buck Blvd. Substation. The Buck Blvd. Substation will also be connected to a proposed IID118-mile single circuit new 500 kV transmission line connecting to the SCE Devers Substation north of Palm Springs, California. This IID 500 kV line is not part of the BEP II AFC and is not under the permitting jurisdiction of the Energy Commission although its need is engendered by BEP II.

Water to operate the BEP II facility is proposed to be supplied by one additional groundwater well having the capability to pump up to 3,000 gallons per minute (gpm). Supply and wastewater treatment systems being constructed as part of the approved BEP I are proposed to be duplicated. A third evaporation pond is proposed to be added for BEP II.

A more complete description of the project that includes the proposed site layout and regional maps is contained in the **PROJECT DESCRIPTION** section of this PSA.

STAFF'S ASSESSMENT

Each technical area section of the PSA contains a discussion of impacts, and where appropriate, mitigation measures and conditions of certification. The PSA includes staff's assessment of:

- the environmental setting of the proposal;
- impacts on public health and safety, and measures proposed to mitigate these impacts;
- environmental impacts, and measures proposed to mitigate these impacts;
  the engineering design of the proposed facility, and engineering measures proposed to ensure the project can be constructed and operated safely and reliably;
- project closure;
- project alternatives;
- compliance of the project with all applicable laws, ordinances, regulations and standards (LORS) during construction and operation;
- environmental justice for minority and low income populations; and
- proposed conditions of certification.

Staff has prepared its preliminary analyses and has made preliminary recommendations for most technical areas, while in some technical areas, staff was unable to make recommendations due to incomplete information, or incomplete project events related to processes required by the Cal-ISO, federal, state and local agencies. The status of each technical area is summarized below.

SUMMARY OF PROJECT RELATED IMPACTS

Staff believes that as BEP II is currently proposed, the project will not comply with all applicable laws, ordinances, regulations, and standards (LORS), and that significant adverse direct, indirect, and cumulative impacts will occur. Noteworthy issues remain in some of the technical areas noted below. For a more detailed review of potential impacts, see staff's technical analyses. The following identifies the items necessary for completion of the FSA and provides a discussion of associated issues.

Technical Area	Complies with LORS	Impacts Mitigated
Air Quality	No	Incomplete
Biological Resources	Incomplete	Incomplete
Cultural Resources	Yes	Incomplete
Efficiency	Yes	Yes
Facility Design	Yes	Yes
Geology & Paleontology	Yes	Yes
Hazardous Materials	Yes	Yes
Land Use	Incomplete	Incomplete
Noise	Yes	Yes
Public Health	Yes	Yes
Reliability	Yes	Yes
Socioeconomic Resources	Yes	Incomplete
Soil & Water Resources	No	Incomplete
Traffic & Transportation	Incomplete	No
Transmission Line Safety/Nuisance	Yes	Yes
Transmission System Engineering	No	No
Visual Resources	Yes	Yes
Waste Management	Yes	Yes
Worker Safety and Fire Protection	Yes	Incomplete

AIR QUALITY

Outstanding Data

1. The Final Determination of Compliance (FDOC) for the Mojave Desert Air Quality Management District (MDAQMD).
2. A wind erosion control plan for the Water Conservation Offset Program (WCOP) must be submitted prior to completion of the FSA. The plan must be reviewed and approved by the Federal Natural Resources Conservation Service (NRCS).

Discussion

The U.S. Environmental Protection Agency (EPA) and California Air Resources Board (CARB) requested that many changes be included in the MDAQMD’s FDOC, and it is not yet clear whether MDAQMD will implement all of the requests made by these oversight agencies. It is not clear whether BEP II would be likely to comply with requirements for Best Available Control Technologies (BACT) because the determination made by MDAQMD is inconsistent with U.S. EPA and CARB recommendations. The FDOC should include revised BACT limits, revised limits during startup and shutdown periods, and new conditions addressing the inlet air chillers that were added by the applicant in July 2003.

The U.S. EPA believes that the offset strategy for PM10 is invalid and that special case-by-case approval of the offset interpollutant trading scheme is required. If these concerns are not addressed before the MDAQMD issues the FDOC, additional mitigation may be necessary to address project-related impacts to PM10 and ozone from precursor emissions. Because the offset strategy is incomplete, staff cannot determine whether BEP II would be likely to comply with MDAQMD offset rules or whether impacts to PM10 and ozone would be mitigated to a level of insignificance.

The WCOP that the applicant proposes would result in rotational fallowing of agricultural land in the area. Agricultural operations in the existing conditions cause emissions of fugitive dust, which contributes to elevated PM10 concentrations. It is not presently clear whether the WCOP will eventually be reviewed and approved by the Federal Natural Resources Conservation Service (NRCS) to ensure that proper conservation practices are utilized on the fallowed lands. Staff expects that wind erosion and fugitive dust emissions from the fallow lands would be minimized if the recommendations of this agency are included in the WCOP.

BIOLOGICAL RESOURCES

Outstanding Data

3. The Biological Assessment with full mitigation must be accepted as complete by the U.S. Fish and Wildlife Service (USFWS).
4. A mitigation and monitoring plan for burrowing owl must be proposed that is acceptable to California Department of Fish and Game (CDFG).

Discussion

To obtain a USFWS determination, the federal lead for the project, Western, has submitted the Biological Assessment, and asked for concurrence with their determination of no effect to desert tortoise. The USFWS has requested additional information before they can make a concurrence.

The applicant must make a choice of assuming presence of burrowing owls and undergoing 2081(b) consultation, performing winter and spring surveys during this proceeding, or accepting a condition of certification that may delay construction until the proper breeding and winter surveys can be completed to show absence of burrowing owls.

CULTURAL RESOURCES

Outstanding Data

5. Caithness and staff must complete consultation with Native Americans to identify and evaluate resources that could be impacted by the project, and address such information in the FSA.

6. The City of Blythe must determine through their planning process whether there would be ground disturbing activities required outside of the project site.

Discussion

Consultation with Native Americans to identify and evaluate resources is not yet complete. Staff is continuing contacting Native American groups and individuals to identify resources that could be impacted by the project. If there is a resource that qualifies as a Native American sacred site that would be impacted by the project, then mitigation measures would be developed to reduce the impacts to less than significant, if possible.

The City of Blythe has not determined through their planning process whether there would be ground disturbing activities, such as the widening of access roads, required outside of the project site. This could impact portions of CA-RIV-6370H or deposits that have not yet been identified though the survey process. Decisions by the City and information about resources that could be impacted will be provided in the Final Staff Assessment.

LAND USE

Outstanding Data

7. A full description of the WCOP including a parcel by parcel identification of farmland classifications, irrigation status, permanently retired parcels, and Williamson Act status.

Discussion

Any permanent retirement of productive farmland by the WCOP must be mitigated to avoid impacts to agricultural lands and conflicts with Williamson Act contracts. The applicant must obtain the Riverside County Agriculture Commissioner's and County Planning Department's review of WCOP-proposed parcels for any Williamson Act contract conflicts.

Outstanding Data

8. Caithness must receive from the City a recommendation regarding a height variance and site plan application.

Discussion

The project is consistent with the City's General Plan and generally consistent with the City's zoning. However, the project would exceed the City's 34-foot height restriction in the Heavy Industrial Zone. The Energy Commission must receive from the City a recommendation for a variance to allow a structure height in excess of the height limit. The applicant has not yet requested the City to provide a recommendation for site plan approval and a height variance. If the City recommends approval of the variance, the nonconformance with City LORS would be resolved.

Outstanding Data

9. The Airport Land Use Commission (ALUC) has determined that the project is inconsistent with the County Land Use Plan (CLUP), while recommending conditions if the Energy Commission decides to approve the project. The City has not yet submitted its analysis and recommendation regarding the ALUC's determination. This will be required for the completion of the FSA.

Discussion

Because the City Council for the City of Blythe could overrule the ALUC, staff needs to receive the City's analysis and recommendation in order to decide whether to recommend that the CEC accept the ALUC's determination of inconsistency. The potential for land use compatibility impacts, including cumulative impact, of visual water vapor plumes and thermal plumes caused by the project are being studied by staff and will be addressed in the FSA.

SOCIOECONOMICS

Outstanding Data

10. A complete description of the proposed fallowing of croplands associated with the WCOP is needed from Caithness. This should include details on the exact location of acreage being fallowed, such as township and range and number of acres and type of crop to be fallowed.

Discussion

Implementation of the WCOP would result in changes to the agricultural use of some lands in the vicinity of the proposed project. However, the applicant has provided no information as to which currently cultivated lands might be fallowed. Therefore, staff cannot determine whether a significant impact to the farm labor, farm services, and farm supply sector will occur or whether it would disproportionately impact the minority and low-income population of Mesa Verde.

TRAFFIC AND TRANSPORATION

Outstanding Data

11. Additional analysis is needed to assess the impact of BEP II on aviation traffic safety. This analysis will be based on studies of the potential impact of visual and thermal plumes on Blythe Airport operations. These studies will include assessment of the cumulative impact of BEP I and BEP II. Staff is conducting these studies but will require certain information from Blythe I and Blythe II.

Discussion

Staff cannot reach a conclusion regarding the consistency of the project with the CLUP, and cannot complete the Traffic and Transportation section of the PSA until there is sufficient information to allow a thorough analysis of the impact of BEP II on airport traffic safety. Staff is facilitating additional studies and is coordinating with state, local, and federal agencies.

Outstanding Data

12. Caithness may need to apply to the FAA for the evaluation of transmission towers that may be taller than the HRSG stacks.

Discussion

Caithness needs to identify the transmission towers that will be used near the airport. The transmission towers may be taller than the HRSG stacks, requiring a reevaluation by FAA of its determination of no hazard to air navigation.

Outstanding Data

13. Description of an alternative route for oversize and overweight loads that avoids use of Hobsonway is needed.

Discussion

The City's recent renovation of Hobsonway does not allow for oversize and overweight loads to be transported on Hobsonway from the railroad offloading point near Commercial Street.

TRANSMISSION SYSTEM ENGINEERING

Outstanding Data

15. The System Impact Study (SIS) and/or Facility Study (FS) to be performed by **SCE** must include:
    - a Power Flow study under 2006 summer peak and 2006 spring conditions;
    - a Transient Stability study;
    - a Short Circuit study; and
    - must address staff's concerns as stated in the Preliminary Staff Assessment about modeling of interconnection facilities and the new 500 kV bulk power line, and must include all downstream adverse impacts and selected mitigation measure(s) for each criteria violation.

      According to staff's discussion with the representative of K. R. Salines & Associates, the Transient Stability study and Short Circuit study to be performed by SCE must include analyses for the affected Western, SCE, IID and SDG&E systems.
16. The SIS and/or FS to be performed by **Western** must:
    - include a Power Flow study under 2006 summer peak and 2006 spring conditions;

- ∉ address staff's concerns as stated in the Preliminary Staff Assessment about modeling of interconnection facilities and the new 500 kV bulk power line;
- ∉ include all downstream adverse impacts and selected mitgation measure(s) for each crteria violation.

If SCE does not perform a Transient Stability study and a Short Circuit study for the affected Western system, the SIS and/or FS to be performed by Western must include such analyses for the affected Western system.

17. The SIS and/or FS to be performed by **IID** must :
    - ∉ include a Power Flow study under 2006 summer peak and 2006 spring conditions;
    - ∉ address staff's concrens as stated in the preliminary Staff Assessment about modeling of interconnection facilities and the new 500 kV bulk power line, and to include all downstream adverse impacts and selected mitgation measure(s) for each crteria violation.

    If SCE does not perform a Transient Stability study and a Short Circuit study for the affected IID and SDG&E systems, the SIS and/or FS to be performed by IID must include such analyses for the affected IID and SDG&E systems.
18. For any reasonably forseeable new or modified downstream faclilities, environmental impact information and identification of mitigation measures are required.
19. Review, Analysis and Conclusions by the Cal-ISO on the SCE, Western and IID SISs and/or Facility studies.
20. Final layout plans with description of faclities and one line diagrams for the BEP II Switchyard, Buck Blvd. Substation, the new 500 kV line and Devers substation (Coachella or Dillon Road Substation be included if necessary) with proposed equipment and their ratings in concurrence with the respective transmission owner.
21. A copy of the "request to interconnect BEP II" by Caithness to Western, and the associated study plan and schedules for completing the SIS and/or FS.
22. A copy of the "request to terminate the proposed new 500 kV line" by IID or others to SCE and Western, and the associated study plan and schedules for completing the SIS and/or FS.
23. Evidence that the CEQA/NEPA reviews have made adequate progress to ensure that construction of the 500 kV line and its schedule have been finalized by IID, that the 500 kV line has been approved for termination by SCE and Western, and that a schedule for building any other new or modified downstream facilities necessary to comply with reliability criteria have been finalized.

Discussion

Approximately 8+ interconnection scenarios have been suggested by the applicant since filing the AFC. At the April 10, 2003 conference call, the applicant selected the TSE Figure 2 interconnection configuration for permitting purposes. Staff's analysis thus far analyzes only the TSE Figure 2 configuration and the above list of outstanding data pertains to that configuration. Staff has recently been informed by the Cal-ISO and

SCE that three additional Interconnection configurations (scenarios) have been requested by the applicant for study by the Cal-ISO, SCE and/or Western and IID. Until the applicant completes their feasibility study stage of the project definition and settles on a project definition, staff cannot analyze the “whole of the action” e.g. the “project”. The applicant must select one interconnection configuration, provide an adequate SIS/FS performed by the Transmission Provider(s) for one and only one interconnection configuration and include all relevant information per the above. The selected interconnection configuration must be one for which the applicant seeks a license of, and defines and describes their final project.

Staff has also concluded that the TSE Figure 2 interconnection configuration does not conform with LORS and the absence of a project definition and identification of transmission construction timelines indicates the BEPII is infeasible because it will not be able to deliver its power to the load.

WATER RESOURCES

Outstanding Data

24. Discharge of wastewater from the BEP II facility to the proposed evaporation pond could result in potentially significant impacts to soil and groundwater quality as a result of leaks or overflows. Corrected evaporation pond calculations are needed, and should also be submitted to the Regional Water Quality Control Board (RWQCB).
25. Draft waste discharge requirements (WDRs) for the evaporation ponds are needed at least 60 days prior to the release of the FSA.
26. Quantify the amount of auxiliary firing and reflect the associated water use in revised heat and water balances.
27. Various submittals have been in conflict regarding the type of inlet cooling. Therefore, the heat and water balances should be revised to reflect the type of inlet cooling that will be used at the plant.
28. Construction and operations at the BEP II site could result in increased stormwater runoff volumes and peak flowrates leaving the BEP II site resulting in potentially significant impacts. Revised design calculations for the stormwater retention basin are needed that demonstrate that the proposed retention basin can contain the runoff produced by a 100-year event and would meet the City of Blythe’s freeboard requirements.
29. A revised retention basin design that includes an emergency spillway or outlet structure to safely route potential overflows away from the containment berm are needed.
30. Because the BEP II project as proposed by Caithness would cause significant impacts to the water supply and its users, would not conform to applicable LORS and State policy, and there is a feasible alternative to the use of Colorado River groundwater; staff recommends the project be amended to use the Dry Cooling alternative developed in the Water Supply and Cooling Options Study (Appendix

A), or equivalent. The Applicant should submit an amended AFC including a description of project design and operational plan for the BEP II.

31. Staff needs the full report on the 2002 groundwater quality sampling of BEP I production wells including the results that did not exceed the primary or secondary drinking water standards. The Blythe Lemon Ranch gasoline leak may require further evaluation for potential significant impacts related to entrainment and migration of any contaminate plume.
32. Reasonably quantitative conservation of water by the Water Conservation Offset Program (WCOP) cannot be determined because there is no comprehensive plan available. Wind and water born soil erosion related potentially significant impacts to fallowed lands could occur due to inadequate mitigation measures not consistent with NRCS recommended guidelines. A complete WCOP is needed that includes detailed procedures for implementation, management, monitoring, reporting, and verification of its effectiveness for both quantitative conservation of 3300 AFY of Colorado River groundwater and mitigation of erosion related potentially significant impacts to fallowed lands. The complete draft WCOP should be made available for review and comment by agencies to include the USBR, CRB, PVID, and NRCS at least 60 days prior to the date scheduled for publication of the FSA.
33. Responses to unanswered Staff Data Requests.

Discussion

As currently proposed, BEP II would cause significant water supply related direct and cumulative impacts, and would not conform to applicable LORS. Additional information noted above is needed to reach final conclusions on those aspects of the project.

The Energy Commission has recently formally adopted policy related to water use by power plants in the State in the 2003 Integrated Energy Policy Report (IEPR) that recognizes the importance of the need to conserve the State's water supply. In support of this policy, an alternative to the proposed project has been recommended by staff.

The information noted above is needed to adequately evaluate the proposed project design with the WCOP. This additional data is not necessary if the preferred Dry Cooling alternative is implemented.

WORKER SAFETY AND FIRE PROTECTION

Outstanding Data

34. Prior to the issuance of the FSA, the applicant and the City of Blythe Fire Department must provided staff with adequate relevant and specific information for staff to conduct a thorough analysis and make a determination regarding impacts to local services.

Discussion

In December 2002, the City of Blythe indicated it was preparing a needs assessment for BEP II (Blythe 2002). This needs assessment was to have been provided to staff in

May 2003 as per statements made by the applicant. However, on July 27, 2003, staff received notice from the applicant that the needs assessment would not be competed and submitted to the CEC until after certification.

Without a Fire Services Needs Assessment for BEP II and without specific information from the fire departments on their expected needs, staff cannot make a determination at this time whether impacts on the fire and emergency services would be significant.

ENVIRONMENTAL JUSTICE

Outstanding Data

35. In order for staff to complete the environmental justice analysis, the applicant will need to provide full details on the proposed fallowing of croplands associated with the WCOP including the exact location of acreage being fallowed (such as township and range) the number of acres and type of crop to be fallowed, and number of workers associated with the crop and acreage.

Discussion

The previously approved BEP I is the subject of an environmental justice complaint with the U. S. Department of Energy (DOE), and BEP II would be the second power plant constructed within two miles of a minority and low-income population. The use of the Colorado River groundwater and the WCOP may impact the region’s farm labor, farm services, and farm supply sector thereby creating environmental justice implications.

CONCLUSION AND RECOMMENDATION

There is insufficient information for staff to conclude the project would conform with all applicable LORS, and whether the project's potential impacts on public health and safety, the environment, and transmission system will be adequately mitigated. Substantial additional information for Air Quality, Biology, Cultural Resources, Land Use, Socioeconomics, Traffic and Transportation, Transmission System Engineering (TSE), Worker Safety and Fire Protection, and Water and Soil Resources is necessary to complete the FSA. This information has been requested in previous data requests and in conference calls; however, Caithness has not provided a schedule of when this data will be provided for review.

Since filing the AFC, Caithness has discussed and analyzed many project interconnection and termination configurations with the Energy Commission, IID, Western, SCE, and the Cal-ISO. To better understand the project’s interconnection and termination configurations and its feasibility, staff has requested a copy of Caithness’ interconnection study requests and study plans submitted to Western, SCE and IID, and the completed System Impact and Facilities Studies from SCE, Western, and IID for the final selected interconnection configuration only. Caithness has not provided a schedule when this information will be provided and when the studies will be completed.

Once the above noted System Impact and Facilities Studies are completed and Caithness selects measures to mitigate system impacts that are acceptable to SCE, IID, Western, and the Cal-ISO, Caithness should submit an AFC amendment describing these project changes and provide the necessary detailed analysis for all the relevant technical disciplines impacted by these changes. The selected interconnection and termination configuration should be the one for which Caithness is seeking a permit from the Energy Commission and it must be consistent with all other filings Caithness makes with SCE, IID, Western, the Cal-ISO, or other transmission providers.

Staff concludes that Caithness' proposed use of groundwater to cool the plant would cause a significant direct impact to the Palo Verde Irrigation District water supply and its users, and contribute to a significant impact to the State's Colorado River water supply and its users. In light of these significant impacts and the requirement that the state reduce its use of Colorado River water over the coming years, staff recommends the project be cooled without the use of groundwater but through dry-cooling technology that has been successfully employed by the Sutter Project in the Sacramento Valley, and will be used for the 590-megawatt (MW) Okay Mesa project in San Diego County, and the 548-megawatt Reliant Energy Bighorn facility south of Las Vegas. There are currently five dry-cooling power projects proposed in Nevada. Staff recommends that the applicant provide an amendment to the AFC changing the project to dry-cooling. The analysis of this project change would be included in the FSA.

Considering the number of outstanding issues, staff recommends that the PSA be circulated for review and comment, and that the Committee hold a Status Conference. This will allow the applicant to identify when the outstanding information will be provided and the Committee to determine the next set of milestones in the project schedule. Staff will be prepared at the Status Conference to offer its recommendations on the project schedule.

BLYTHE ENERGY PROJECT PHASE II
(02-AFC-1)
PRELIMINARY STAFF ASSESSMENT

INTRODUCTION

William Pfanner

On February 19, 2002, an application for certification (AFC) was filed with the California Energy Commission (Energy Commission) for the Blythe Energy Project Phase II (BEP II). The proposed project would be located next to the Blythe Energy Project (BEP I) that was approved by the Energy Commission in 2001. BEP II would be a nominally rated 520 MW combined-cycle power plant consisting of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTGs), one 180 MW steam turbine generator, and supporting equipment.

BEP II would be located entirely within the approved BEP I site boundary (see BEP I Petition for Amendment I-B, dated November 23, 2001). BEP II may utilize some existing facilities at the BEP I site including the approved BEP I Control/ Administration and Maintenance Buildings. Other BEP facilities that may be expanded to serve BEP II include the ground water supply and treatment system, waste water treatment system, fire protection facilities and site access roads. Natural gas would be supplied to the BEP II plant by the natural gas pipeline being constructed as part of the approved BEP I.

This Preliminary Staff Assessment (PSA) is the Energy Commission staff's independent analysis of the BEP II project. The PSA describes the following:

- the proposed project;
- the existing environment;
- whether the facilities can be constructed and operated safely and reliably in accordance with applicable laws, ordinances, regulations and standards (LORS);
- the environmental consequences of the project including potential public health and safety impacts;
- cumulative analysis of the potential impacts of the project, along with potential impacts from other existing and known planned developments;
- mitigation measures proposed by the applicant, staff, interested agencies and intervenors which may lessen or eliminate potential impacts;
- the proposed conditions under which the project should be constructed and operated, if it is certified; and
- project alternatives.

The analyses contained in this PSA are based upon information from the: 1) AFC, 2) subsequent AFC amendments, 3) responses to data requests, 4) supplementary information from local and state agencies and interested individuals, 5) existing documents and publications, 6) independent field studies and research, and 7) comments at workshops. The analyses for most technical areas include discussions of proposed conditions of certification. Each proposed condition of certification is followed by a proposed means of "verification." The PSA presents conclusions and proposed conditions that apply to the design, construction, operation and closure of the proposed facility.

The Energy Commission staff's analyses were prepared in accordance with Public Resources Code section 25500 et seq. and Title 20, California Code of Regulation section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code, §21000 et seq.).

ORGANIZATION OF THE PRELIMINARY STAFF ASSESSMENT

The **INTRODUCTION** section explains the purpose of the PSA and its relationship to the Energy Commission's siting process. The **PROJECT DESCRIPTION** section provides a brief overview of the project including its purpose, location and major project components.

The **ENVIRONMENTAL** and **ENGINEERING** evaluations of the proposed project follow the **PROJECT DESCRIPTION**. In the **ENVIRONMENTAL** analyses, the project's environmental setting is described, environmental impacts are identified and their significance assessed, and the project's compliance with applicable laws is reviewed. The mitigation measures proposed by the applicant are reviewed for adequacy and conformance with applicable laws; if any remaining unmitigated impacts are identified, staff proposes additional mitigation measures and project alternatives. Staff's conclusions and recommendations are discussed, and proposed conditions of certification are included, if applicable. In the **ENGINEERING** analyses, the project is evaluated in each technical area with respect to applicable laws and performance objectives. Each technical section ends with a discussion of conclusions and recommendations. Proposed conditions of certification are included, if applicable.

ENERGY COMMISSION SITING PROCESS

The California Energy Commission has the exclusive authority to certify the construction, modification and operation of thermal electric power plants 50 megawatts (MW) or larger. The Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, §25500). The Energy Commission must review power plant AFCs to assess potential environmental impacts including potential impacts to public health and safety, potential measures to mitigate those impacts (Pub. Resources Code, §25519), and compliance with applicable governmental laws or standards (Pub. Resources Code, §25523 (d)).

The Energy Commission's siting regulations require staff to independently review the AFC and assess whether the list of environmental impacts contained is complete, and whether additional or more effective mitigation measures are necessary, feasible and available (Cal. Code Regs., tit. 20, §§1742 and 1742.5(a)). Staff's independent review shall be presented in a report (Cal. Code Regs., tit. 20 , §1742.5). The Final Staff Assessment is that report.

In addition, staff must assess the completeness and adequacy of the health and safety standards, and the reliability of power plant operations (Cal. Code Regs., tit. 20, §1743(b)). Staff is required to develop a compliance plan (coordinated with other agencies) to ensure that applicable laws, ordinances, regulations and standards are met (Cal. Code Regs., tit. 20, §1744(b)).

Staff conducts its environmental analysis in accordance with the requirements of the California Environmental Quality Act (CEQA). No additional Environmental Impact Report (EIR) is required because the Energy Commission's site certification program has been certified by the Resources Agency as meeting all requirements of a certified regulatory program (Pub. Resources Code, §21080.5 and Cal. Code Regs., tit. 14, §15251 (k)).

The staff prepares a PSA and presents for the applicant, intervenors, agencies, other interested parties and members of the public, the staff's analysis, conclusions, and recommendations. Where it is appropriate, the PSA incorporates comments received from agencies, the public and parties to the siting case, and comments made at the workshops.

Staff will provide a comment period to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings. During the period after the publishing of the PSA, staff will conduct workshops to discuss its findings, proposed mitigation, and proposed compliance-monitoring requirements. Based on the workshops and written comments, staff may refine its analysis, correct errors, and finalize conditions of certification to reflect areas where agreements have been reached with the parties, and publish a Final Staff Assessment (FSA).

The FSA is only one piece of evidence that will be considered by the Committee (two Commissioners who have been assigned to this project) in reaching a decision on whether or not to recommend that the full Energy Commission approve the proposed project. At the public hearings, all parties will be afforded an opportunity to present evidence and to rebut the testimony of other parties, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

Following the hearings, the Committee's recommendation to the full Energy Commission on whether or not to approve the proposed project will be contained in a document entitled the Presiding Members' Proposed Decision (PMPD). Following publication, the PMPD is circulated in order to receive written public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD. At the close of the comment period for the revised PMPD, the PMPD is submitted to the full Energy Commission for a decision. Within 30 days of the Energy Commission decision, any party may appeal the decision to the Energy Commission.

PUBLIC AND AGENCY COORDINATION

Publicly noticed workshops have been held in the City of Blythe, Ontario and Sacramento. Topics discussed include: air quality, biology, cultural resources, geology, land use, noise, socioeconomics, traffic and transportation, transmission system engineering, visual resources, soil and water, and other issues.

In addition to these workshops, extensive coordination has occurred with the numerous local, state and federal agencies that have an interest in the project. Particularly, Energy Commission staff has worked with the City of Blythe, Riverside County, Western Area Power Administration (Western), Imperial Irrigation District (IID), Palo Verde Irrigation District (PVID), U.S. Bureau of Reclamation (USBR), Colorado River Board, Caltrans, Mojave Desert Air Quality Management District (MDAQMD), California Air Resources Board, U.S. Environmental Protection Agency (EPA) and the Regional Water Quality Control Board (RWQCB) to identify and resolve issues of concern. In addition, Commission staff has coordinated the review and analysis of the project with U.S. Fish and Wildlife Service, California Departments of Fish and Game, and Parks and Recreation, U.S. Army Corp of Engineers, intervenors, and the interested residents of the community.

ENVIRONMENTAL JUSTICE

Executive Order 12898, "Federal Actions to address Environmental Justice in Minority Populations and Low-Income Populations," focuses federal attention on the environment and human health conditions of minority communities and calls on federal agencies to achieve environmental justice as part of this mission. The order requires the U.S. Environmental Protection Agency (USEPA) and all other federal agencies (as well as state agencies receiving federal funds) to develop strategies to address this issue. The agencies are required to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations.

For all siting cases, Energy Commission staff conducts an environmental justice screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in USEPA's National Environmental Policy Act (NEPA) Compliance Analysis" dated April 1998. The purpose of the screening analysis is to determine whether there exists a minority or low-income population within the potentially affected area of the proposed site.

California statute, section 65040.12 (c) of the Government Code, defines "environmental justice" to mean "fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies." In light of the progress made by federal environmental agencies on environmental justice, the Energy Commission has examined federal guidelines pursuant to its desire to follow environmental justice principles for the environmental review of this project.

The U. S. Environmental Protection Agency (EPA) issued draft guidance for implementing Executive Order 12898, which was signed by President Clinton in 1998 and relates to considering EJ, in the context of the National Environmental Policy Act (NEPA), 42 U.S.C. section 4321 et seq. This guidance is entitled "Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analysis" (dated April 1998). In addition, the Council on Environmental Quality has developed additional guidance entitled "Environmental Justice Guidance Under the National Environmental Policy Act" (dated December 1997).

The steps recommended by these guidance documents to assure compliance with the Executive Order are: (1) outreach and involvement; (2) a screening-level analysis to determine the existence of a minority or low-income population; and (3) if warranted, a detailed examination of the distribution of impacts on segments of the population. Though the Federal Executive Order and guidance are not binding on the Energy Commission, staff finds these recommendations helpful for implementing this environmental justice analysis. Staff has followed each of the above steps for the following 11 sections in the PSA: Air Quality, Hazardous Materials, Land Use, Noise, Public Health, Socioeconomics, Soils and Water, Traffic and Transportation, Transmission Line Safety/Nuisance, Visual Resources, and Waste Management. The discussion of staff's review of environmental justice is contained in each of the above sections.

The purpose of the EJ screening analysis is to determine whether a low-income and/or minority population exists within the potentially affected area of the proposed site. Staff conducted the screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analysis" (Guidance Document) dated April 1998. People of color populations, as defined by this Guidance Document, are identified where either:

∉ the minority population of the affected area is greater than fifty percent of the affected area's general population; or

∉ the minority population percentage of the area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis.

The EPA requires local air districts to perform an environmental justice analysis for Prevention of Significant Deterioration permits. As the lead agency for reviewing applications to build new thermal electric generation facilities greater than 50 megawatts, the Energy Commission performs an environmental justice analysis in part to assist the local air districts.

ENVIRONMENTAL JUSTICE OUTREACH

The Energy Commission's environmental justice outreach program is facilitated by the Public Advisers Office (PAO). This is an ongoing process that to date has involved the following.

<u>Libraries</u>: On July 18, 2002, the PAO sent the Blythe II AFC to the Parker Arizona Public Library; the Riverside Main Library; the Palo Verde Valley District Library and the Brawley Public Library. To assist the public in locating the AFC, the PAO prepared a poster to announce the project with key contact information. Along with the library AFC, the PAO sent 25 copies of the one-page bilingual project description and the poster. The librarians were asked to place the posters and project descriptions in areas accessible to the public.

Schools: July 30, 2002, the PAO sent 20 bilingual project descriptions and a poster to both the Palo Verde Unified School District and the Palo Verde Community College District.

Chamber of Commerce: The PAO also sent 3 posters and 20 bilingual project descriptions to the Palo Verde/Riverside County Chamber of Commerce. The Chamber of Commerce was asked to place the posters on various town informational bulletin boards and place the project descriptions in areas accessible to the public.

Newspapers: The PAO prepared 4,500 bilingual newspaper inserts announcing the time, date and location of the Informational Hearing and Site Visit. The inserts were sent to the "Palo Verde Times" newspaper for distribution in their September 4, 2002, edition.

Further Outreach: In addition, the PAO sent bilingual notice of the Informational Hearing and Site Visit to the Palo Verde/Riverside Chamber of Commerce; the Palo Verde Community College District; the Palo Verde Unified School District; the Brawley Public Library; the Riverside Main Library; the Parker Arizona Public Library; and the Palo Verde Valley District Library for distribution

Notices: Notices of the "Informational Hearing and Site Visit" and the "Data Request and Issue Resolution Workshop" scheduled for September 9, 2002, were mailed to the General Public, Property Owners, Agency lists and the parties listed on the BEP II Proof of Service. The Commission's list server also sent the notice to all subscribers on the BEP II electronic notice lists.

Meetings: The AFC review process involved hearings and workshops to receive comments from the public. The Public Adviser attended the Informational Hearing and Site Visit in Blythe as well as the Issue Identification Workshop on September 9, 2002.

For the workshops dated September 10, and November 5 and 6, the PAO provided copies of the project description, status reports and general information on how to obtain assistance from the PAO.

PROJECT DESCRIPTION

William Pfanner

INTRODUCTION

As defined in the AFC, the Revised AFC and responses to Data Requests, the Blythe Energy Project Phase II (hereinafter referred to as BEP II) is a nominally rated 520 megawatt (MW) combined-cycle power plant. The proposed project is an addition to the approved Blythe Energy Project (BEP I) described in 99-AFC-8, on file with the California Energy Commission (Energy Commission). BEP II consists of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTGs), one 180 MW steam turbine generator, and supporting equipment.

BEP II is adjacent to the approved BEP I site boundary on the Expansion site approved by the Energy Commission as an amendment to BEP I (See BEP I Petition for Amendment I-B, dated November 23, 2001). BEP II may utilize some existing facilities at the BEP I site including the approved BEP I Control/Administration and Maintenance Buildings. Other BEP I facilities that may be expanded to serve BEP II include the groundwater supply, fire protection facilities and site access roads. Natural gas will be supplied to BEP II plant by the natural gas pipeline being constructed as part of the approved BEP I.

It should be noted that the applicant (Caithness Blythe II, LLC) provided staff with responses to Data Requests that have resulted in changes in the project description not reflected in the AFC or AFC amendments.

Specifically, the Revised AFC provides a project description that does not accurately define how the power generated at the Blythe II project will be interconnected to downstream systems. In March 2003, the applicant provided Data Response 179a, citing the Blythe Area Regional Transmission Flow Analysis (BART Study) as defining how BEP II will interconnect with downstream systems. The BART Study analyzed the Blythe area's regional transmission system including the feasibility of selected transmission options to support the reliable interconnection of the 520 MW BEP II project. The study shows 8+ scenarios of transmission lines extending offsite from the Blythe II project. In a conference call on April 10, 2003, the applicant proposed an interconnection plan that would tie Blythe II to the Buck Boulevard Substation and a proposed Imperial Irrigation District (IID) 118-mile 230 kV or 500kV transmission line connection to the Devers Substation. Therefore, although it is not specifically contained in the AFC, this one BART Study alternative is the BEP II project description interconnection configuration Caithness Blythe II is seeking to license and is the project description staff assessed in this PSA.

GENERATION FACILITY DESCRIPTION, DESIGN AND OPERATION

The BEP II site is located within the City of Blythe, approximately five miles west of the center of the City. Figure 1 provides the regional setting; Figure 2 provides a map depicting the area surrounding the site. The original BEP I site boundary included 76 acres. Blythe Energy secured the rights to use the adjacent 76 acres (2 parcels) from Riverside Power, LLC, a subsidiary of Caithness Energy on December 30th, 2001.

Subsequently, BEP I amended its license to expand the BEP I site boundary to accommodate BEP II and reconfigure the evaporation ponds for BEP I. Therefore, the total BEP I site area was expanded to 152 acres. The BEP II power facilities would be located on the western portion of the 152 acre BEP I site. Figure 3 illustrates the site plan for BEP I and BEP II.

The project site is located east of the Blythe Airport, which is currently owned by Riverside County and operated by the City of Blythe. The Project site is on an intermediate plateau, about 70 feet in elevation above and west of the Colorado River Valley and the City of Blythe and about 60 feet below the elevation and east of the Blythe Airport. The topography of the project site is flat. The BEP sites (BEP I and II) are bounded on the south by Hobsonway and on the east by Buck Boulevard. Hobsonway is a paved highway running east/west parallel to and one-quarter mile north of Interstate 10 (I-10). Buck Boulevard has been paved as part of the approved BEP I. Buck Boulevard runs along the eastern side of the approved BEP I property line and runs north from Hobsonway. The north boundary of the BEP I and II properties is on an unpaved easement dedicated for extending Riverside Drive.

BEP II will be electrically interconnected to the Buck Blvd. Substation, located at the northeastern corner of the approved BEP I site. The Western Area Power Administration (Western) constructed the Buck Blvd. substation as part of the BEP I and currently owns and operates the existing facility. Some of the additional facilities required in the Buck Blvd. substation for BEP II have already been evaluated and approved as part of the Western BEP I Facility Study. However, to facilitate the 500 kilovolt (kV) single circuit from the BEP II Integration switchyard, the Buck Blvd. substation would be expanded to include three 500 kV switch busses and a transformer.

The Buck Blvd. substation will connect to an approximately 118-mile 500 kV signal circuit transmission line connecting to the Devers Substation north of Palm Springs, California, proposed by Imperial Irrigation District (IID). The IID 500 kV line is not under the permitting jurisdiction of the Energy Commission and is being evaluated by the U.S Department of the Interior Bureau of Land Management (BLM) and IID under the Desert Southwest Transmission Line Project Environmental Impact Statement (EIS)/Environmental Impact Report (EIR).

Process Description

As defined in the AFC and supplemental filings, the power plant will consist of two Siemens Westinghouse V84.3a F-Class combustion turbine generators (CTG), two heat recovery steam generators (HRSGs) with duct burners; a single condensing Steam Turbine Generator (STG); a deaereating surface condenser; a bank of mechanical draft wet cooling towers; and associated support equipment. The F-Class CTG refers to a series of gas combustion turbines using advanced combustion technology developed in the 1990s which achieve combined cycle efficiencies near 58% with reduced emissions. The two largest suppliers of these types of turbines are General Electric and Siemens-Westinghouse. Each of the two CTGs will generate approximately 170 MW. The CTGs will be equipped with either an evaporative inlet cooling system or a chilled water inlet air cooling system using mechanical refrigeration equipment and chillers to increase plant output during periods of high ambient temperature conditions. The exhaust gas from each CTG is routed to a triple pressure HRSG to generate steam for the STG. Steam from the two HRSGs is combined and taken to one triple pressure STG. Duct firing will be provided in the HRSGs, and will be used to supplement steam generating capacity during summer conditions when exhaust energy from the CTGs declines. Approximately 180 MW will be produced by the steam turbine. Cooling water for the STG condenser is provided by circulating water through wet cooling towers. These primary plant processes are supported by auxiliary and ancillary equipment referred to as "Balance of Plant" (BOP), which includes an automated control system. The BEP II is expected to have an average annual availability greater than 95% (it will be available to operate more than 95% of the time). Most of the time, the plant is expected to operate at full load. The design does allow the flexibility to rapidly adjust the generation output or for cycling the plant on and off as required to meet demand.

The AFC proposes that the plant will be designed and controlled to meet the required emission limits. NO_x emissions will be controlled to 2.5 ppm by volume, dry basis corrected to 15% oxygen. This emission level will be achieved by a combination of the dry low NO_x combustors in the CTGs and a Selective Catalytic Reduction (SCR) system in the HRSG. Carbon monoxide (CO) will be controlled to 5 ppm by volume at 15% oxygen in the CTG combustors; however CO will increase upward to 8.4 ppm by volume during operation between 75% and 80% load and during duct firing. VOC emissions will be controlled to 1 ppm and ammonia slip will be controlled to 10 ppm. PM_{10} emissions from the cooling water towers will be minimized by a high efficiency drift elimination design.

Power Plant Cycle

CTG combustion air will flow through the inlet air filters, inlet air cooling system, and air inlet ductwork into the compressor section of the CTG. The air will be compressed as it flows through the 17 stages of the compressor, where it then enters the CTG combustion chamber. Natural gas fuel will be injected into the combustion chamber and ignited. The hot combustion gases will expand through the turbine sections of the CTGs, causing them to rotate and drive the electric generators and CTG compressors.

The hot combustion gases then exit the turbine sections and enter the HRSG. As the hot gas passes through the sections of the HRSG, heat is transferred from the hot gases to the surfaces of the tube bundles through which water is flowing. Water will be converted to superheated steam and delivered to the steam turbine at three pressures: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP). The use of multiple steam delivery pressures will provide an increase in cycle efficiency and flexibility. High-pressure steam, delivered to the HP section of the steam turbine, will exit the HP section as cold reheat steam and be combined with IP steam to pass through the reheater section of the HRSGs. This mixed, reheated steam (called "hot reheat") will then be delivered to the IP steam turbine section. Steam exiting the IP section of the steam turbine will be mixed with LP steam and expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the surface condenser, which transfers heat to cooling water circulating in tube bundles. The steam is condensed to water and is delivered back through the cycle to the HRSG feedwater system. The cooling water will circulate through a mechanical draft wet cooling tower where the latent heat will be dissipated to the atmosphere.

The air inlet system provides filtered air to the combustion turbine compressor. The system is equipped with multi-stage, self cleaning and static filters. Silencers are installed to reduce the noise emissions from the gas turbine compressor inlet. The CTGs and accessory equipment will also be contained in a turbine hall with engineered noise control features. The inlet air cooling system will be either an evaporative type system or a mechanical chiller system. The selection of air cooling system will be decided during the final design stage by the Project applicant.

Major Electrical Equipment and Systems

The BEP II will generate electrical power at 16 kV, and step the voltage up to 500 kV for delivery to the electrical grid. Power will be transmitted to the Buck Blvd Substation owned and operated by Western on a 2,500 foot long 500 kV line. Some station power will be used onsite for loads for the Project such as pumps, fans, control systems, and general facility loads, including lighting, heating, ventilation and air conditioning. Station power will also be converted to DC via battery chargers for supply to control systems and for backup power to critical loads such as oil pumps in the event that AC power supply is lost.

The electrical system can be described according to voltage levels:

- 500 kV - Main switchyard and grid connection
- 161/230 Kv-connection at Buck Blvd. substation
- 16 kV - Generator voltage
- 4.16 kV - Station supply to low voltage transformers and large motor loads
- 480 volt - MCC's for small auxiliary motors
- 120/240 volt - Lighting, HVAC, receptacles, and small motor loads
- 125 volt DC - Switchgear control and backup power to critical loads
- 24 volt DC - Instrumentation and control power

Fuel System

The BEP II will use the same natural gas fuel source as the approved BEP I. Fuel gas will be supplied to the Project from the interconnection with the El Paso Gas System. As described in BEP I, the El Paso Gas source is on the eastern or Arizona side of the Colorado River. The new line has been constructed from this point, under the river and then about 11 miles to the plant. This new gas line has the capability to supply natural gas to both BEP I and the proposed BEP II.

The natural gas consumption during base load operation of the BEP II is approximately 84,400 MMbtu per day or approximately 31 million MMbtu per year. The pressure of natural gas delivered to the site via pipeline is expected to be 550 to 800 pounds per square inch gauge (psig). The range of pressure is higher than the inlet pressure required by the CTGs. The gas will flow through gas scrubber/filtering equipment, a gas pressure control station, and flow metering equipment before entering the combustion turbines or duct burners. A pipeline will be constructed from the approved BEP gas supply system on the site property to interconnect with BEP II.

Water Supply and Use

The AFC proposes raw water supply for all plant uses will be from one or two 3000 gpm groundwater wells to be constructed on the plant site or immediate area. The wells will be in addition to the wells that were constructed for BEP I. The maximum rate of usage for BEP II is approximately 3000 gpm for all uses combined. The average rate of usage is expected to be about 2200 gpm. Annual consumption of water is approximately 3,300 acre-feet. Wastewater will be very minimal because the water in the system will be treated and re-cycled to provide total consumption (zero discharge) of water under normal conditions. A septic treatment and disposal system will be provided for sanitary wastewater. An evaporation pond will be provided to receive and dispose by evaporation any water that cannot be reused. The two BEP I evaporation ponds will serve as a backup. These systems are described in the Waste Management section of the PSA. Additional details regarding requirements, supply, quality and treatment are given in the following sections.

Water Requirements

Water use requirements include makeup water for the cooling systems, demineralized water for makeup to the steam system and potable water. The evaporative inlet air cooling system will be another water use. The largest requirement is makeup to the circulating cooling water system due to evaporation. In order to minimize the amount of water taken from the wells, the water is reused and recovered whenever possible.

Demineralized water uses include makeup water for the HRSG steam cycle and supply to the evaporative air inlet cooling system, if evaporative cooling is used. Demineralized water will be produced with a reverse osmosis (RO) unit in series with an electrodeionization (EDI) unit. The water supply for the demineralizer may be taken from the raw water storage system via the potable water system or from the effluent of the brine concentrator (distillate). The average rate of use of demineralized water will be about 40 gpm for makeup to the HRSG steam cycle. A storage tank with 600,000 gallon capacity will be provided for the demineralized water, to allow operation of the demineralizing unit at more uniform flow rates and to provide backup in the event the demineralizing system is out of service. This will provide about 7 days of backup capacity at the average rate of use. The potable water requirement is far smaller than the other requirements, at an estimated average of 1 gpm.

Providing water for the fire protection system is another requirement of the water system. BEP II will have a fire protection system integrated with the BEP I fire protection system. A connection to the BEP I fire protection system will be provided to share stored water between the projects. The fire ring for BEP I will be extended to cover the BEP II facilities. In addition to water in the raw water storage tank, the on-site wells will be capable of restoring the raw water supply at an estimated maximum rate of 6,000 gpm with the two wells pumping.

Water Treatment Plant

The project's water treatment plant will consist of an evaporator (brine concentrator) for process waste treatment, a reverse osmosis (RO) unit for potable water processing, and an RO unit and an electrodeionization (EDI) unit for demineralized water processing.

The evaporator works on a mechanical vapor recompression process. At design conditions it will have 416 gallons per minute of cooling tower blowdown as feed. Approximately 94.5 percent of the feed is returned to the project as distillate and 4.5 percent is directed to the evaporation ponds as brine.

Hazardous Wastes

Hazardous wastes generated by the BEP II will be typical of modern power plant operation. Waste lubricating oil will be recovered and recycled by a waste oil recycling contractor. Used oil filters will be disposed of in a Class I landfill. Spent SCR catalyst will be recycled by the supplier or disposed of in a Class I landfill. Workers will be trained to handle any hazardous waste generated at the site.

Chemical cleaning wastes will consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning of the HRSGs, acid cleaning solutions used for chemical cleaning of the HRSGs after the units are put into service, chemical solutions used for periodic cleaning of the brine concentrator tube surfaces, and turbine wash and HRSG fireside wash waters. These wastes, which are subject to high metal concentrations, will be stored temporarily onsite in portable tanks. They will be disposed of in accordance with applicable regulatory requirements.

Surface Water Runoff – Retention Basin

Surface water runoff from the area used for the power plant and auxiliary systems will be discharged to a stormwater retention basin. The BEP I stormwater retention basin is located at the southern portion of the BEP I site. The BEP I retention basin will be utilized to contain runoff during construction. Surface water runoff from the BEP II power island will be collected in the BEP I stormwater retention basin. The stormwater retention basin will be an earth embankment constructed from on-site materials. The retention basin will be designed to capture and percolate the water in accordance with City of Blythe design standards.

Since the BEP I site slopes gently from the northwest to the southeast, the final grading and associated drainage appurtenances have been constructed to accept offsite flows from the west and north. Most of the offsite flows from the north are intercepted and directed easterly along the north side of Riverside Avenue to a storm water inlet structure located at the northwest corner of the Riverside Avenue/Buck Boulevard intersection. This structure is capable of accepting a peak flow of 120 cubic feet per second (cfs) which is conveyed to the retention basin located at the south end of the BEP I site by twin 42-inch diameter storm drains.

The BEP I retention basin encompasses an area of approximately 11 acres with depths of about 20 feet. The basin is capable of accommodating 8,989,000 cubic feet (206 acre-ft) of runoff. The basin was constructed by excavating the existing soils and constructing earthen embankments.

Onsite flows from the BEP I power island area will be conveyed via drainage channels. The BEP I design has been approved by the CBO. These drainage channels are capable of accommodating a peak discharge of 90 cfs.

The construction of the Riverside Avenue secondary access road westerly to the Blythe Airport will include three concrete cross-gutters that will accept minor offsite storm water flows from the north. These flows will be channelized into drainage swales that will be graded from north to south on both the east and west sides of the relocated evaporation basins. These trapezoidal swales will also be sized to accommodate onsite drainage from the water treatment plant area and the open areas surrounding the relocated evaporation basins. The swales will terminate at the east and west ends of the west retention basin with peak discharges of 50 and 10 cfs, respectively. The swale along the west side of the evaporation basins will also be sized to intercept minor flows from the airport property located westerly of the BEP I site.

Project Construction

Construction of the generating facility for the BEP II, from site preparation and grading to commercial operation, is expected to last approximately 18-22 months. The applicant has proposed that construction will begin in the 3rd quarter of 2004. This will depend on the provision of the information identified in the PSA and the ability to resolve outstanding critical issues.

Table 3.0-4
Project Schedule Major Milestones

Activity	Date
Begin Construction	3rd Quarter 2004
Startup and Test	2nd Quarter 2006
Commercial Operation	3rd/4th Quarter 2006

During construction, land around the BEP II power island will be used for construction laydown and parking. Construction access to the Project site will be from Interstate 10 to Hobsonway and then to Buck Blvd.

The average workforce on the Project during construction will be approximately 232 including construction craft persons and supervisory, support, and construction management personnel. The peak construction workforce of 387 is expected to occur during the 12th month of construction.

Construction will be scheduled 7 days a week and 24 hours a day as needed. Additional hours may be necessary to make up schedule deficiencies or to complete critical construction activities. During the start-up phase of the BEP II, some activities will continue 24 hours per day, 7 days per week.

REFERENCES

BEP II (Blythe Energy Project Phase II). 2002a. Submittal of the Application for Certification (AFC), Vol 1 & 2. 02/20/2002 (tn: 24604)

BEP II (Blythe Energy Project Phase II). 2002d. Revised Application for Certification for Blythe II. 07/03/2002 (tn: 26100)

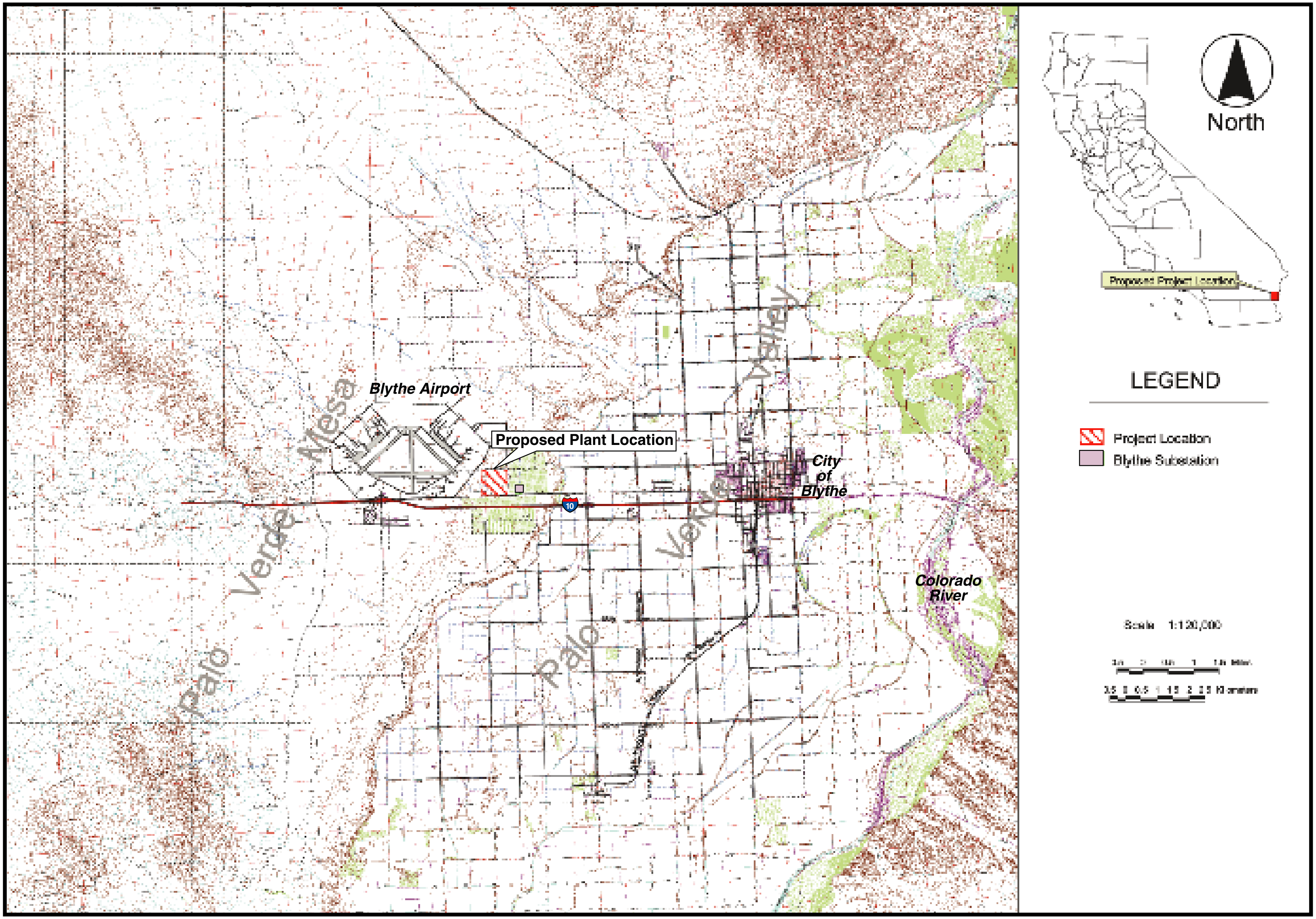
BEP II (Blythe Energy Project Phase II). 2002f. Data Responses #1-102 (set #1). 09/30/2002 (tn: 26909)

BEP II (Blythe Energy Project Phase II). 2003b. Second Round Data Responses #103-188. 03/14/03 (tn: 28226)

BEP II (Blythe Energy Project Phase II). 2003e. Response to Data Request #189-235. 06/13/2003 (tn: 29006)

PROJECT DESCRIPTION - FIGURE 1

Blythe Energy Project II - Regional Location of the Proposed Project

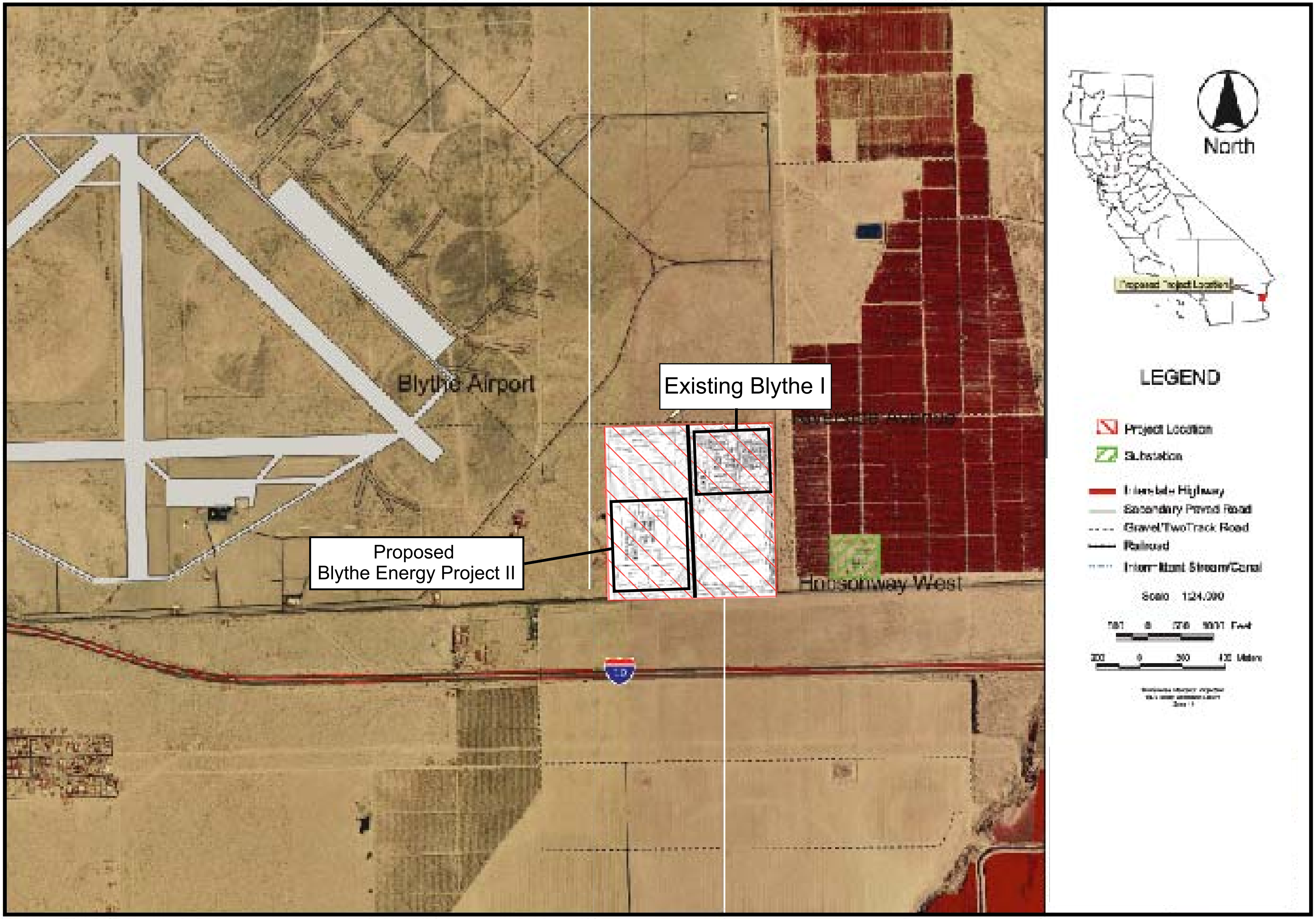


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: AFC Figure 2.0-1

PROJECT DESCRIPTION - FIGURE 2

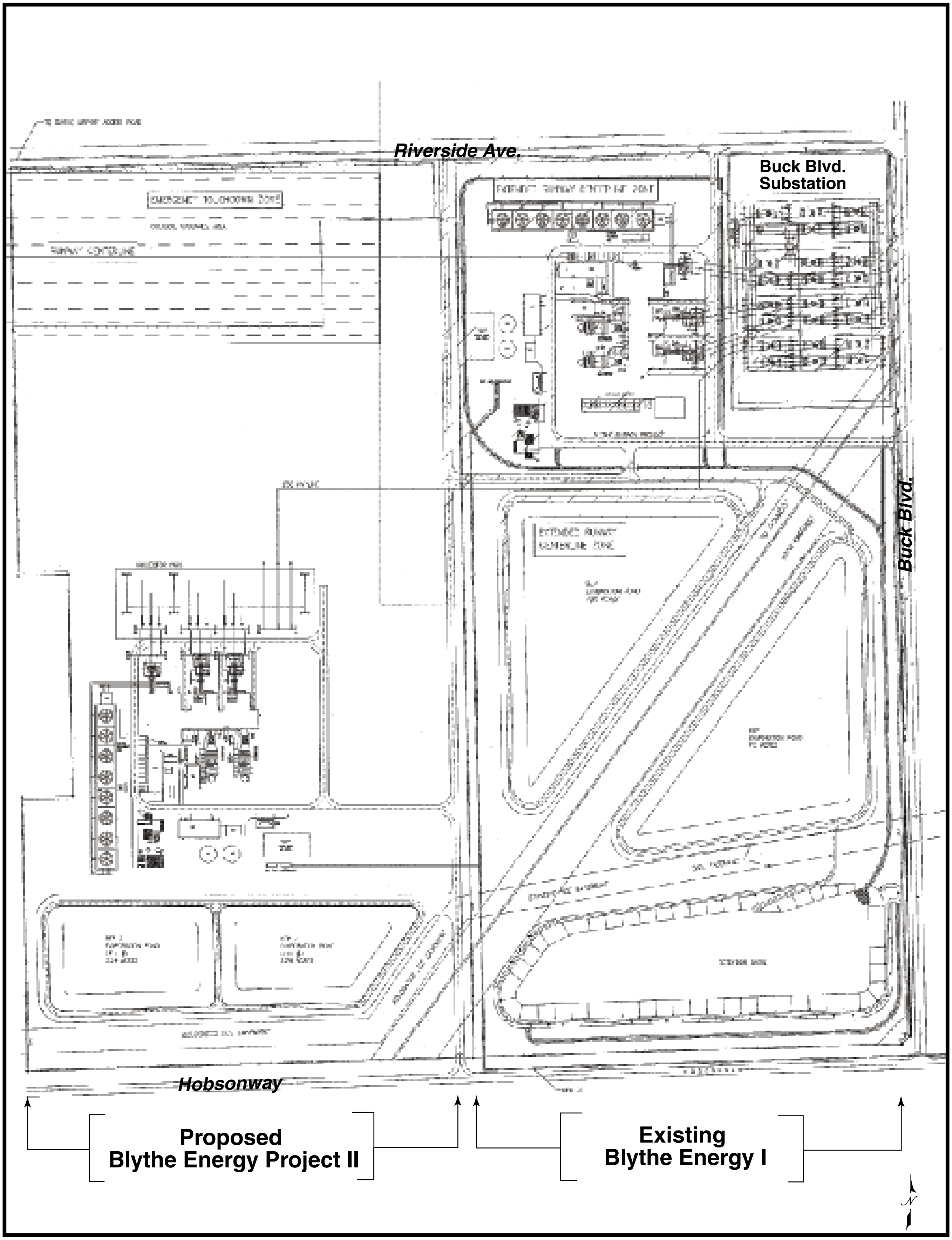
Blythe Energy Project II - Immediate Vicinity of Proposed Project



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: AFC Figure 2.0-3

PROJECT DESCRIPTION - FIGURE 3
Blythe Energy Project II - Site Plan / Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: AFC Figure 36-1

Environmental

Assessment

AIR QUALITY

Brewster Birdsall

INTRODUCTION

This analysis evaluates the expected air quality impacts of construction and operation of the Blythe Energy Project Phase II (BEP II). The Energy Commission staff evaluated the following major points:

- whether the proposed Blythe Energy Project Phase II is likely to conform with applicable Federal, State and Mojave Desert Air Quality Management District (MDAQMD, or District) air quality laws, ordinances, regulations and standards (Cal. Code Regs., tit. 20, § 1744(b)); and
- whether the proposed Blythe Energy Project Phase II is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards and whether the mitigation proposed for BEP II is adequate to lessen the potential impacts to a level of insignificance (Cal. Code Regs., tit. 20, § 1742(b)).

The analysis deals with criteria pollutants that are managed according to federal or state ambient air quality standards to protect public health. They include ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), reactive organic gases (ROGs, including volatile organic compounds, or VOCs), and particulate matter less than ten microns in diameter (PM_{10}) and less than 2.5 microns in diameter ($PM_{2.5}$).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal Clean Air Act requires that any new major stationary sources of air pollution and any major modifications to existing major stationary sources obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). Its requirements differ depending on the attainment status of the area where the major facility is to be located. Prevention of Significant Deterioration (PSD) requirements apply in areas that are in attainment with the national ambient air quality standards. Nonattainment NSR applies in areas where certain pollutants do not in comply with national ambient air quality standards. The entire program, including both PSD and nonattainment NSR, is referred to as the federal NSR program.

Title V of the federal Clean Air Act requires implementation and administration of an operating permit program to ensure that large sources operate in compliance with the requirements included in the Code of Federal Regulations (CFR), Title 40, Part 70 (40 CFR 70). A Title V permit contains all of the requirements specified in different air quality regulations that affect an individual project.

Title IV of the federal Clean Air Act requires implementation of an acid rain permit program (40 CFR 72). These regulations require subject facilities to obtain emission allowances for oxides of sulfur (SOx) emissions.

The U.S. Environmental Protection Agency (U.S. EPA) has reviewed and approved the Mojave Desert Air Quality Management District (MDAQMD, or District) regulations for the nonattainment NSR, Title V, and Title IV programs. These federal permitting programs have been delegated to the MDAQMD for implementation (District Regulation XII for federal Title V and Regulation XIII for nonattainment NSR). The MDAQMD rules and regulations implementing the federal programs are as stringent as the federal regulations.

The federal PSD program (40 CFR 52.21) is implemented by the U.S. EPA, which means that an independent application must be filed with the U.S. EPA in order to secure this federal permit. BEP II originally submitted the PSD application in May 2002, and the U.S. EPA provided a preliminary analysis of compliance in April 2003 that has not yet been formally released.

The Blythe Energy Project Phase II is also subject to the federal New Source Performance Standards (NSPS) contained in 40 CFR 60. Enforcement of NSPS has been delegated to the MDAQMD (District Regulation IX). The proposed combined cycle power plant must comply with the requirements of NSPS Subparts Da and GG (for the duct burners and stationary gas turbines, respectively). The federal NSPS allowable emissions concentration for NOx is 75 ppmvd (parts per million volume dry) at 15% O_2, and the NSPS requirement for SO_2 emissions concentration is 150 ppm at 15% O_2.

The first phase and existing Blythe Energy Project (BEP I) is a major stationary source for nitrogen oxides (NOx), carbon monoxide (CO), and PM_{10}. According to the requirements of the MDAQMD NSR programs, BEP II would be a major modification to this major source. Modification of BEP I by adding BEP II would result in a new stationary source that would be classified as major for these three pollutants plus VOC and SOx (MDAQMD 2002a).

STATE

California State Health and Safety Code, Section 41700, requires that: "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

LOCAL

As part of the Energy Commission's licensing process, the MDAQMD prepared a Preliminary Determination of Compliance (PDOC, MDAQMD 2002a) for the Blythe Energy Project Phase II. The PDOC evaluates whether and under what conditions the proposed project will comply with the applicable rules and regulations, as described below. The review by the MDAQMD for the PDOC is conducted in a manner that is equivalent to that for an authority to construct. The Energy Commission staff coordinates its analysis with that for the PDOC. Provided successful completion of the Energy Commission's licensing process and incorporation of the District's conditions into the decision granted by the Energy Commission, the Determination of Compliance serves as an equivalent to an Authority to Construct. A Permit to Operate would be issued by the District provided the construction is in compliance with the conditions of the Determination of Compliance and the Energy Commission decision.

The project is subject to certain specific MDAQMD rules and regulations that are summarized below:

Regulation II – Permits

RULE 201 – PERMITS TO CONSTRUCT

Requires the District's authorization prior to construction of a new facility.

RULE 203 – PERMIT TO OPERATE

Requires the District's authorization before a new facility commences operations.

RULE 221 – FEDERAL OPERATING PERMIT REQUIREMENTS

Requires submittal of an application for a federal operating permit within twelve months of commencing operation.

Regulation IV – Prohibitions

RULE 401 – VISIBLE EMISSIONS

This rule contains general requirements limiting visible emissions to no darker than Ringelmann No. 1 (20 percent opacity) for periods greater than three minutes in any hour.

RULE 402 – NUISANCE

Prohibits any emissions "which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such person or public or which cause or have a natural tendency to cause injury or damage to business or property."

RULE 403 – FUGITIVE DUST

Regulates operations that may cause fugitive dust emissions into the atmosphere. Emissions of fugitive dust from transport, handling, construction or storage activities shall not remain visible in the atmosphere beyond the property line of the emission source, or exceed 100 micrograms per cubic meter when determined as the difference between upwind and downwind samples collected on high volume samplers at the property line for a minimum of five hours. These limits are not applicable when the wind speed instantaneously exceeds 40 kilometers (25 miles) per hour, or when the average wind speed is greater than 24 kilometers (15 miles) per hour. The average wind speed determination shall be on a 15 minute average at the nearest official air-monitoring station or by wind instrument located at the site being checked.

RULE 403.2 – FUGITIVE DUST FOR THE MOJAVE DESERT PLANNING AREA

Limits emissions from construction activities, publicly maintained unpaved roads, and activity on other public lands to ensure that dust emissions in the Mojave Desert Planning Area are managed. This only applies to sources in San Bernardino County.

RULE 406 – SPECIFIC CONTAMINANTS

Limits the emissions of sulfur compounds to no greater than 500 parts per million by volume (ppmv), and a number of other contaminants (such as bromine, hydrogen chloride and fluorine) to specific ppmv levels.

RULE 409 – COMBUSTION CONTAMINANTS

Limits discharging of combustion contaminants (PM_{10}) to no greater than 0.1 grains per dry standard cubic foot (gr/dscf).

RULE 430 – BREAKDOWN PROVISIONS

Requires reporting of breakdowns and excess emissions.

RULE 431 – SULFUR CONTENT OF FUELS

Limits sulfur content of gaseous fuel to 800 ppm, calculated as hydrogen sulfide at standard conditions, and liquid or solid fuel to 0.5 percent by weight.

RULE 475 – ELECTRIC POWER GENERATING EQUIPMENT

Limits the oxides of nitrogen (NOx) emissions of any electric power generating equipment to no more than 80 ppm if using gaseous fuel, 160 ppm if using liquid fuel and 225 ppm if using solid fuel.

RULE 476 – STEAM GENERATING EQUIPMENT

Limits the emissions of any fuel combustion equipment to no more than 200 pounds per hour of oxides of sulfur (SOx), 140 pounds per hour of NOx, or 10 pounds per hour of combustion contaminants.

Regulation IX – Standards For Performance For New Stationary Sources

Adopts the requirements of the federal New Source Performance Standards (40 CFR 60) by reference. The federal NSPS requirements for stationary gas turbines and duct burners are described with other federal requirements, above.

Regulation XI – Source Specific Standards

RULE 1158 – ELECTRIC UTILITY OPERATIONS

Establishes NOx emission standards and other requirements for electric utility operations including installation of an approved continuous emission monitoring (CEM) system, reporting and an approved emission control plan.

Regulation XII – Federal Operating Permits

Establishes administrative requirements for obtaining a federal operating permit (federal Clean Air Act Title V) and an acid rain permit (Title IV) by the appropriate dates.

Regulation XIII – New Source Review

RULE 1302 – PROCEDURES, NEW SOURCE REVIEW

Provides administrative procedures for the processing of applications for permits to construct and operate new and modified stationary sources.

Rule 1302(C)(3)(b), Determination of Offsets, states that the applicant shall provide an offset package which contains evidence of offsets eligible for use pursuant to the provisions of Rule 1305.

Rule 1302(C)(3)(b)(iii) states that the District must determine that the offsets are real, enforceable, surplus, permanent and quantifiable and that permit modifications required pursuant to Rule 1305 or Regulation XIV have been made. The District would approve the use of the offsets subject to the approval of California Air Resources Board (CARB) and U.S. EPA.

Rule 1302(D)(5)(b)(iii) requires that the applicant certify in writing that all facilities which are under the common control of the applicant in the State of California, are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act.

RULE 1303 – REQUIREMENTS, NEW SOURCE REVIEW

Provides specific requirements for new or modified stationary sources including Best Available Control Technology (BACT) and offsets. A modification of a major source must apply BACT for each nonattainment air pollutant for which the potential to emit is greater than 25 pounds per day or 25 tons per year. Offsets must be provided for all pollutants that exceed the specified trigger levels.

RULE 1305 – EMISSIONS OFFSETS

Provides the procedures and formulas for quantifying and determining the eligibility of emission reduction credits (ERCs) available for use as offsets in accordance with Rule 1303.

Rule 1305(B)(5) allows for the use of interbasin offsets from upwind air districts that are outside the Mojave Desert Air Basin. Rule 1305(B)(6) allows for the use of interpollutant offset trading as long as there is technical justification for such a trade and the combined emissions increase from the proposed project and the reductions from the interpollutant offsets do not cause or contribute to a violation of an ambient air quality standard.

New emissions of NOx and PM_{10} from BEP II must be offset because BEP II would emit these nonattainment pollutants (or precursors) in quantities greater than the offset applicability thresholds in Rule 1303(B). At the time of BEP I permit issuance, BEP I emissions for VOC and SOx did not exceed offset threshold values, and, therefore, did not require offsets. However, BEP II emissions when combined with the emissions from BEP I will now exceed the Rule 1303(B) offset threshold for both VOC and SOx. Therefore, the entire quantity of VOC and SOx emissions from BEP I and BEP II must be offset by the BEP II modification.

RULE 1306 - ELECTRIC ENERGY GENERATING FACILITIES

This rule includes the additional administrative requirements for projects that are required to obtain licensing from the Energy Commission and specifies that a determination of compliance would be prepared by the District.

Regulation XIV– Emission Reduction Credit Banking

RULE 1402 – EMISSION REDUCTION CREDIT REGISTRY

Provides administrative procedures for the registry of ERCs for stationary sources. The requirements include the specific timing of an application for an ERC and criteria for approval of the ERC.

Rule 1402(A)(1)(e)(ii) defines emission reductions to be eligible for ERCs if such reductions are actual emission reductions and either recognized by the District in writing or were included in the emission inventory after the shutdown or modification occurred.

RULE 1404 – EMISSION REDUCTION CREDIT CALCULATIONS

Provides methods to calculate the ERC available, as the difference between the historical actual emissions and the proposed emissions. Emission reductions must be adjusted to reflect only those reductions that are in excess of the reductions achievable by Reasonably Available Control Technology or required by applicable District rules.

SETTING

METEOROLOGICAL CONDITIONS

The general climate of California is typically dominated by the eastern Pacific high pressure system centered off the coast of California. In the summer, this system results in low inversion layers and clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rainstorms originating in the Gulf of Alaska and striking Northern California.

The City of Blythe is located near the border of the Mojave Desert and the Sonoran Desert in the Lower Colorado Valley. Hot, dry summers and mild winters with scant precipitation define the climate. The semi-permanent Pacific High over the eastern Pacific Ocean during the summer months blocks low pressure systems from passing through the area. This results in hot summers, with average daily maximum temperatures during the summer months over 105 ºF. During the winter, the area does not often experience frost. Daily maximum temperatures during the winter months average around 68 ºF, with average wintertime low temperatures being around 40 ºF (WRCC 2002).

During the winter months, the Pacific High weakens and migrates to the south, allowing Pacific storms into California. In addition, the area receives some moisture during the summer monsoon season from the wind flowing up the Colorado River Valley from the Gulf of California. However, due to the rain shadow effect of the mountainous terrain west and south of the Blythe region, the average annual rainfall in the area is only 3.7 inches.

Analysis of the local wind rose diagrams (a graph showing the average wind speed and direction in the location) provided by the applicant in the Application for Certification (AFC) indicate that the surface winds in the area are strongly influenced by the southwest-northeast orientation of the Colorado River directly to the east of the project site (BEP II 2002d, AFC Figures 7.7-4 to 7.7-8). During the summer months (April through September), winds are predominately from the southwest, while during the winter months winds are predominately from the northeast. The winds are calm approximately 15 percent of the time annually and seven percent of the time during the summer months.

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing, and thus less stability. During these conditions there is more air pollutant dispersion and therefore usually reduced air quality impacts near any single air pollution source. During the winter months between storms, however, very stable atmospheric conditions occur, resulting in very little mixing. Under these conditions, little air pollutant dispersion occurs, and consequently higher air quality impacts may result from stationary source emissions. Because lower mixing heights generally occur during the winter, along with lower mean wind speeds and less vertical mixing, dispersion occurs less rapidly.

EXISTING AIR QUALITY

The project is located in the Riverside County portion of the Mojave Desert Air Basin and is under the jurisdiction of the Mojave Desert Air Quality Management District. The U.S. EPA and CARB each designate the status of local air quality through a comparison with the ambient air quality standards (AAQS). The state standards (CAAQS), established by CARB, are typically more restrictive than the federal or national standards (NAAQS), which are established by the U.S. EPA. The state and federal ambient air quality standards are listed in **AIR QUALITY Table 1**. As indicated in this table, the averaging times for the various standards (the duration over which they are measured) range from hourly to annually. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant per cubic meter of air (mg/m^3 and $\mu g/m^3$).

AIR QUALITY Table 2 shows the area designation status of the Mojave Desert Air Basin for each criteria pollutant for both the federal and state ambient air quality standards. Only ozone and PM_{10} are designated as nonattainment under the CAAQS.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	1 Hour	0.12 ppm (235 μg/m^3)	0.09 ppm (180 μg/m^3)
	8 Hour	0.08 ppm (160 μg/m^3)	—
Respirable Particulate Matter (PM_{10})	24 Hour	150 μg/m^3	50 μg/m^3
	Annual Average	50 μg/m^3	20 μg/m^3
Fine Particulate Matter ($PM_{2.5}$)	24 Hour	65 μg/m^3	—
	Annual Average	15 μg/m^3	12 μg/m^3
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 μg/m^3)	—
	1 Hour	—	0.25 ppm (470 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Sulfur Dioxide (SO_2)	Annual Average	0.03 ppm (80 μg/m^3)	—
	24 Hour	0.14 ppm (365 μg/m^3)	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	—	0.25 ppm (655 μg/m^3)
Sulfates (SO_4^{2-})	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	—
Hydrogen Sulfide(H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.010 ppm (26 μg/m^3)
Visibility Reducing Particulates	1 Observation	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

AIR QUALITY Table 2
Federal and State Area Designations for the Mojave Desert Air Basin

Pollutants	Federal Classification	State Classification
Ozone	Unclassified/Attainment	Moderate Nonattainment
PM_{10}	Unclassified	Nonattainment
NO_2	Unclassified	Attainment
CO	Unclassified	Unclassified
SO_2	Unclassified	Attainment

LOCAL AIR QUALITY DATA

Local ambient air quality conditions are normally determined by a network of monitoring stations, however there are few stations near Blythe. The original BEP I modeling analysis used Twentynine Palms monitoring data for estimated ambient background concentrations. The Twentynine Palms monitoring station is located approximately 90 miles west-northwest of the project site, and indicates violations of the state 24-hour

PM_{10} standard and both the state and federal 1-hour ozone standard. Twentynine Palms is downwind of industrial and urban areas, particularly Victorville and Barstow and to a certain extent, the Los Angeles Basin. Conversely, there are very few sources of industrial pollutants near Blythe. Therefore, it is likely that ozone concentrations in the Blythe area are lower than those measured at Twentynine Palms. An analysis of the trend of ambient ozone concentrations around Blythe was conducted in response to BEP I Data Request 201 in August 2000, which confirmed this conclusion. This analysis was updated for year 2000 ambient air quality data (BEP II 2002d, AFC Appendix 7.7-G), which again concluded that the air quality in Blythe is better than or equal to 1992 air quality, the last year for which Blythe area data are available.

The most-recent air quality data from the Twentynine Palms station is presented in **AIR QUALITY Table 3**. Data in **bold** format represents the highest historical value and the value used in the staff assessment of project impacts.

No information on ozone concentrations in the Blythe area is available from the Arizona Department of Environmental Quality (ADEQ). The ADEQ does operate an ozone monitoring station in Yuma, approximately 90 miles south of Blythe along the Colorado River. For the year 2000, maximum ozone concentrations in Yuma were below the Twentynine Palms concentrations. The maximum monitored ozone concentrations in Yuma were 0.077 ppm (1-hour) and 0.068 ppm (8-hour) (ADEQ 2001).

Ozone

In the presence of ultraviolet radiation, both NOx and VOC go through a number of complex chemical reactions to form ozone. Ozone formation is highest in the spring and summer, when abundant sunshine and high temperatures are available to trigger the necessary photochemical reactions, while concentrations are lowest in the winter. **AIR QUALITY Table 3** summarizes the most-representative ambient ozone data collected from theTwentynine Palms monitoring station.

AIR QUALITY Table 3
Ambient Air Quality Monitoring Data, Twentynine Palms – Adobe Road #2

Pollutant	Standard	1996	1997	1998	2000	2001	2002	Most Restrictive Standard
Ozone	Maximum 1-hour Average (ppm)	0.121	0.115	0.118	0.108	**0.124**	0.099	0.09 (CAAQS)
	Month of Maximum 1-hour	Jul	May	Jun	Aug	Aug	Jun	—
	# of days exceeding CAAQS	19	15	13	16	12	2	—
	Maximum 8-hour Average (ppm)	0.101	0.104	0.110	0.093	**0.112**	0.091	0.08 (NAAQS)
	Month of Maximum 8-hour	Jun	Jul	Jul	Jun	Aug	Jun	—
	# of days exceeding NAAQS	20	14	11	11	9	4	—
PM_{10}	Maximum 24-hour Average ($\mu g/m^3$)	47	30	30	62	**84**	55	50.0 (CAAQS)
	Month of Maximum 24-hour	---	May	Jul	Aug	Aug	May	—
	# of days exceeding CAAQS*	0	0	0	6	12	12	—
	Annual Arithmetic Mean ($\mu g/m^3$)	22.5	16.6	15.6	21	20	**24**	20 (CAAQS)
NO_2	Maximum 1-hour Average (ppm)	0.035	**0.037**	0.036	---	---	---	0.25 (CAAQS)
	Average annual concentration (ppm)	0.006	**0.006**	---	---	---	---	0.053 (NAAQS)
CO	Maximum 1-hour Average (ppm)	1.9	**2**	---	---	---	---	20 (CAAQS)
	Maximum 8-hour Average (ppm)	**1.31**	1.03	---	---	---	---	9 (CAAQS)
SO_2	Maximum 1-hour Average (ppm)	0.005	**0.008**	---	---	---	---	0.25 (CAAQS)
	Maximum 24-hour Average (ppm)	**0.004**	0.002	---	---	---	---	0.04 (CAAQS)
	Annual Average (ppm)	0.001	**0.001**	---	---	---	---	0.03 (NAAQS)

Source: CARB web site: http://www.arb.ca.gov/adam/welcome.html, accessed June 2003.

Highest monitored concentrations, used in this assessment, shown in **bold**.

* Days above the state standard (calculated): Monitoring for the 24-hour PM10 standard is performed once every six days, and the number of days shown exceeding the standard is the actual number of measured days times six.

Respirable Particulate Matter

Respirable particulate matter (PM_{10}) can be emitted directly by a range of sources, including combustion of any fossil fuel, and it can be formed many miles downwind when various precursor pollutants interact in the atmosphere.

Given the right meteorological conditions, gaseous emissions of pollutants like NOx, SOx, and VOC from combustion sources, and ammonia from agriculture, waste-water treatment, or NOx control equipment, can form particulate matter composed of nitrates (NO_3^-), sulfates (SO_4^{2-}), and organics. These pollutants are known as secondary particulates, because they are not directly emitted, but are formed through complex chemical reactions in the atmosphere. Particulate nitrate can be formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. In urbanized areas, the nitrate ion concentrations can be a significant portion of the total PM_{10}. Nitrate ions are only one component of particulate nitrate, which typically takes the form of ammonium nitrate or sodium nitrate.

Secondary particulates are probably a minor fraction of the overall PM_{10} concentrations in the project area because there are few major sources of precursors. In the desert, wind blown dust contributes to elevated PM_{10} concentrations. This means that the make-up of ambient particulate matter in the project area on the days of highest concentrations is largely of a geologic or mineral nature.

AIR QUALITY Table 3, above, shows that the Mojave Desert Air Basin experiences ongoing violations of the state 24-hour PM_{10} standard. The less-stringent federal standards have not historically been violated by ambient PM_{10} concentrations.

Fine Particulate Matter

The U.S. EPA first identified ambient air quality standards for fine particulate matter ($PM_{2.5}$) in 1997. The air agencies in California are now deploying $PM_{2.5}$ ambient air quality monitors throughout the state. Region-specific $PM_{2.5}$ ambient air quality attainment plans, if needed, are due to the U.S. EPA by 2005. The MDAQMD would be responsible for developing an air quality management plan for $PM_{2.5}$, if the Mojave Desert Air Basin is eventually designated as a nonattainment area.

Preliminary data is available for $PM_{2.5}$ from monitoring stations in Victorville starting in 1999. The maximum 24-hour concentrations occurring between 1999 and 2002 was 38.0 $\mu g/m^3$. Compared to the 1997 U.S. EPA standard of 65 $\mu g/m^3$, this area would not exceed the federal standard (CARB web site, accessed June 2003). The highest annual average concentration for 1999 through 2002 was 13.9 $\mu g/m^3$. Compared to the 1997 U.S. EPA standard of 15 $\mu g/m^3$, this area would not exceed the federal standard, but it could exceed the state standard of 12 $\mu g/m^3$. Because a continuous data record is necessary to determine attainment status, the $PM_{2.5}$ attainment status for the Mojave Desert has not yet been designated.

Concentrations of PM_{10} and $PM_{2.5}$ in the Mojave Desert are weakly seasonal, with higher $PM_{2.5}$ concentrations normally occurring in the winter (CARB CD-R 2002, and Almanac 2001). High PM_{10} concentrations from wind blown dust can occur during any time of the year, as shown in **AIR QUALITY Table 3**. Managing $PM_{2.5}$ concentrations will require identifying controllable sources and developing feasible source management strategies. Because PM_{10} includes $PM_{2.5}$ as a subset and reactive precursors that lead to ozone can also lead to $PM_{2.5}$, the established strategies for controlling PM_{10} and ozone precursors (including existing programs for combustion sources) also presently help to reduce $PM_{2.5}$ concentrations.

PROJECT DESCRIPTION AND EMISSIONS

This section describes the project design, project emissions, and air pollutant control devices as described in the Blythe Energy Project Phase II AFC (BEP II 2002d).

CONSTRUCTION PHASE

Project Site

BEP II will be located adjacent to BEP I previously approved by the California Energy Commission on March 21, 2001. BEP II project construction, from site preparation and grading to commercial operation, will require approximately 18-22 months, while the onsite construction schedule requires a total of approximately 16 months. Construction equipment use estimates are based on 6 days per week, 8 hours per day (BEP II, AFC Appendix 7.7-E). Additional construction shifts may be necessary to make up schedule deficiencies. During the commissioning phase, some activities will continue 24 hours per day, 7 days per week (BEP II, AFC p. 2-31).

During construction, approximately 12.4 acres (BEP II, AFC Figure 2.0-24) of the 152-acre parcel (BEP I/BEP II), around the BEP II power island, would be disturbed for temporary construction equipment laydown and parking. Approximately one-half of the total area, or 76 acres, would be disturbed due to construction activities for the power plant and ancillary facilities. Upon completion of the facility, the BEP II power island will occupy about 15-acres of land near the southern portion of the expansion site.

Linear Facilities

BEP II requires no offsite linear facilities, which are in addition to the approved BEP I offsite linear facilities (e.g. transmission line and natural gas pipelines), because of its location to BEP I and its ability to share linear facilities. The transmission interconnection will be to the adjacent Buck Boulevard Substation.

Project Construction Emissions

During the construction period, emissions will be generated from the exhaust of the heavy equipment and fugitive dust from earthwork and activity on unpaved surfaces. Heavy equipment would include loaders and haul trucks to deliver construction materials, excavators and backhoes for earthwork, graders, cranes, lifts, and smaller equipment such as welders, generators, and air compressors. Fugitive dust emissions will occur due to activity on the exposed surfaces at the site, especially those portions that are unpaved.

AIR QUALITY Table 4 summarizes the different levels of criteria pollutants that are estimated to be generated from the 16-month construction phase for BEP II (BEP II 2002d, AFC Table 7.7-19).

The construction equipment and fugitive dust emissions provided above were based on emission factors and load factors published by the U.S. EPA (U.S. EPA, 1991 and 2000). The equipment emission rates assume use of California-required low-sulfur diesel fuel and engines that comply with U.S. EPA off-road equipment emission standards from 1996 (BEP II 2002d, AFC p. 7.7-17). The applicant provided the estimated number of operational hours for each piece of equipment throughout project construction outlined in the AFC (BEP II 2002d, AFC Appendix 7.7-E). For equipment, the mitigation measures identified by the applicant include limiting engine idling time,

AIR QUALITY Table 4
BEP II, Estimated Emissions from Construction
(Hourly Maximum Emissions and Total Emissions)

	NOx		PM_{10}		CO		SOx		VOC	
Equipment	**(lb/hr)**	**(ton)**	**(lb/hr)**	**(ton)**	**(lb/hr)**	**(ton)**	**(lb/hr)**	**(ton)**	**(lb/hr)**	**(ton)**
Onsite Equipment (a)	18.55	10.3	0.83	0.5	3.01	1.9	0.49	0.3	1.11	0.6
Onsite Fugitive Dust (b)	---	---	11.9	6.7	---	---	---	---	---	---

Source: AFC Appendix 7.7-E (BEP II 2002d).

(a) Hourly emission estimates are based on applicant's estimate of total emissions by month (AFC Appendix 7.7-E) divided by 200 hours per month of activity as per applicant's equipment use estimates.

(b) Fugitive dust emissions are based on applicant assessment of 0.156 ton PM_{10}/month/acre with approximately 7.6 acres of the site being worked during any given month or a maximum rate of 1.19 ton PM_{10}/month (AFC Appendix 7.7-E).

shutting down equipment when not in use, and conducting routine preventative maintenance to the manufacturer's specifications (AFC p. 7.7-55). For fugitive dust, emission reductions would be achieved with dust suppression measures specified by the applicant along with those specified in the Energy Commission's Conditions of Certification. The emissions in **AIR QUALITY Table 4** account for the measures the applicant proposes (BEP II 2002b, Data Request #4).

OPERATIONAL PHASE

Equipment Description

The new nominally-rated 520 MW combined cycle power plant would include the following:

- Two Siemens Westinghouse V84.3A F-Class combustion turbine generators (CTGs), each generating approximately 170 MW. Each CTG includes dry low-NOx combustors for NOx reduction. Each CTG would be coupled to a heat recovery steam generator (HRSG) at an estimated maximum capacity of 132 MMBtu/hr with supplemental duct burners and an integral selective catalytic reduction (SCR) system to control NOx emissions.
- Chilled water inlet air cooling system for the CTGs with 4-cell cooling tower (BEP II 2003a).
- One steam turbine generator (STG) capable of generating approximately 180 MW.
- Cooling system for the steam generation system with a surface condenser that is cooled with circulating water from an evaporative cooling tower. The cooling tower would be a linear 8-cell conventional counter-flow mechanical draft design with high-efficiency drift eliminators to minimize drift.
- Aqueous ammonia storage, vaporization, and injection system for SCR.
- Anhydrous ammonia or hydro-chlorofluorocarbon (HCFC) storage system for refrigerant in inlet air cooling system.

- Diesel-fueled fire pump engine (303 hp) for emergency use only.
- Continuous emission monitoring (CEM) system.
- Water Conservation Offset Program (WCOP) that would result in rotational fallowing of agricultural land to offset project water consumption.

Equipment Operation

The Blythe Energy Project Phase II combined cycle power plant will fire exclusively pipeline-quality natural gas. It is designed to provide a nominally rated output of 520 MW. Natural gas would be delivered to the site by the natural gas pipeline for the recently-constructed BEP I. BEP II may also utilize additional facilities at the BEP I site including the BEP I Control/ Administration and Maintenance Buildings. Other BEP I facilities that may be expanded to serve BEP II include the groundwater supply, fire protection facilities and site access roads. BEP II will be electrically interconnected to the Buck Boulevard Substation, constructed by the Western Area Power Administration as part of the BEP I. Water to operate BEP II would be supplied by one additional groundwater well. The applicant is proposing that water use be offset by the Water Conservation Offset Program (WCOP). Under the WCOP, land currently used for agricultural purposes would be left fallow (BEP II 2002d, AFC p. 7.13-23 to 27). Supply water and wastewater treatment systems being constructed as part of the approved BEP I will be duplicated for BEP II. A third evaporation pond will be added for BEP II (BEP II 2002d, AFC p. 2-1).

Emission Controls

Both of the CTGs will be equipped with dry low-NOx (DLN) combustors followed by SCR. With this design, the applicant proposes to limit NOx to 2.5 ppmvd at 15% O_2 (based on a 1-hour average). As a reagent, the SCR system relies on use of ammonia vapor injected to the exhaust stream. The applicant proposes to limit stack emissions of ammonia (known as ammonia slip) to 10 ppmvd at 15% O_2 (3-hour average), except during periods of start-up, shutdown, and malfunction (BEP II 2002d, AFC p. 7.7-28).

Through the use of advanced combustion control, the applicant proposes to achieve CO concentrations of less than 5 ppmvd at 15% O_2 when the CTG loads are 80-100% and 8.4 ppmvd when the CTG loads are between 70-80% without duct firing and 100% load with duct firing, except during periods of startup, shutdown and malfunction (based on a 3-hour average). As a contingency, the applicant would design the HRSG to allow a retrofitted installation of an oxidation catalyst in the event that combustion control could not meet the limits established by the permitting process (BEP II 2002d, AFC p. 7.7-36). Combustion control would also be used to achieve VOC emissions less than 1 ppmvd at 15% O_2 (based on a 1-hour average) for CTG loads at 80-100% with duct firing (BEP II 2002d, AFC p. 7.7-37).

Continuous emission monitors (CEMs) will be installed on the CTG/HRSG exhaust stacks to monitor NOx, CO, and oxygen concentrations to assure adherence with the emission limits. The CEM system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the control room when the level of emissions approaches or exceeds pre-selected limits.

The exclusive use of pipeline-quality natural gas, a relatively clean-burning fuel, will limit emissions of PM_{10} and SO_2. Natural gas contains very little noncombustible gas or solid residues and a small amount of reduced sulfur compounds including mercaptan, thus resulting in relatively low emissions of PM_{10} and SO_2. The applicant anticipates that the supplied natural gas will contain less than 0.5 grains of sulfur per 100 dry standard cubic feet (dscf), which is less than the 1 grain per 100 scf recommended by CARB (AFC p. 7.7-38). The anticipated PM_{10} emission rate is 6 lb/hr (BEP II, AFC Table 7.7-20).

The BEP II cooling tower will be equipped with mist eliminators guaranteed by the manufacturer to limit drift to 0.0006 percent. The applicant proposes a total dissolved solids (TDS) limit of 8,190 mg/l, and a maximum water circulation rate of 146,000 gpm for the cooling tower (BEP II, AFC p. 7.7-38). The inlet air chiller will include a cooling tower equipped with mist eliminators that would reduce drift to 0.001 percent. The applicant proposes a maximum water circulation rate of 17,000 gpm (BEP II 2003a, p. 7.7-3). To provide a reasonable worst-case assessment of impacts to ambient air quality, staff assumes that 100 percent of the TDS would be emitted to the ambient air as PM_{10}.

The cooling tower may also cause emissions of small quantities of organic chemicals, if organic compounds are identified in project wells (see Final Decision for BEP I, Soil & Water Condition #10, page 214, March 21, 2001).

The Water Conservation Offset Program (WCOP) that the applicant proposes would result in rotational fallowing of agricultural land in the area. Agricultural operations in the existing conditions cause emissions of fugitive dust, which contributes to elevated PM_{10} concentrations. According to the applicant's proposal, each landowner that participates in the rotational fallowing would be required to implement erosion control practices (BEP II 2003b). It is not presently clear whether the WCOP will eventually be reviewed and approved by the Federal Natural Resources Conservation Service (NRCS) to ensure that proper conservation practices are utilized on the fallowed lands. Staff expects that wind erosion and fugitive dust emissions from the fallow lands would be minimized if the recommendations of this agency are included in the WCOP. If staff can be assured that NRCS-recommended conservation practices will be implemented,, then wind erosion and fugitive dust emissions from the fallowed lands would likely be reduced as compared to those from actively farmed lands. If the applicant cannot commit to implementation of NRCS-recommended soil conservation practices on the WCOP lands, staff may need to develop additional measures to control wind erosion and any associated PM_{10} emissions.

Project Operating Emissions

Operating the major project components will cause emissions of criteria air pollutants. The assumptions used in estimating the emissions here include:

- manufacturer's guaranteed emission factors;
- the facility operating for approximately 8,760 hours per year;
- a range of load conditions (60% to 100%, with or without duct firing) and a range of ambient temperatures (20°F, 59°F, and 95°F);

- typical operating scenarios for estimating daily and annual emissions based on a worst-case day with five hot starts and one cold start and a worst-case year with 100 hot starts, 50 warm starts and 10 cold starts (AFC pp. 7.7-7 to 8);
- concurrent and continuous operation of the cooling system and inlet chillers; and
- operation of the diesel-fueled fire water pump engine for 52 hours per year.

Independent staff analysis is used to estimate the maximum emissions from the cooling towers at BEP II. Staff assumes that the maximum anticipated level of total dissolved solids (8,190 ppmw) could be emitted as PM_{10}. The emission tables do not show direct $PM_{2.5}$ emissions from any source because an established methodology does not exist for quantifying these emissions for all the sources. Although it is known that a substantial portion of the particulate matter formed during combustion will qualify within the $PM_{2.5}$ subset of PM_{10}, estimates of $PM_{2.5}$ emission rates are not available for the other sources.

During normal operation, the plant will start up and shut down periodically. The amount of time that units are shut down defines whether the subsequent startup is a cold, warm or hot start. The applicant notes that different startup times for each combustion turbine depend on the sequence of the startup, the turbine started first requires slightly more time to come up to steady-state. The expected emission rates during startup and shutdown events are summarized in **AIR QUALITY Table 5**.

AIR QUALITY Table 5
BEP II, Startup and Shutdown Emissions (lb/hr)

Operational Source – Mode	NOx (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)	SOx (lb/hr)	VOC (lb/hr)
Each CTG/HRSG (typ hr during Cold Start, 3.7 hrs)	106.0	6.1	111.0	2.1	5.5
Each CTG/HRSG (typ hr during Warm Start, 2.0 hrs)	151.8	5.7	131.5	2.0	6.4
Each CTG/HRSG (typ hr during Hot Start, 1.2 hrs)	221.2	5.7	143.3	2.2	7.4
Each CTG/HRSG (typ hr during Shutdown, 0.5 hr)	340.0	6.0	96.0	2.0	8.0

Source: BEP II 2002d, AFC Appendix 7.7-A, Vendor Startup Data.

Note: Preliminary data from continuous emission monitors at BEP I indicate that these startup and shutdown emission rates may need to be substantially revised because the preliminary CO emission data from BEP I equipment exceeds these emission rates by approximately a factor of ten.

Emissions during non-startup or shutdown conditions would be fully controlled because all combustion and post-combustion control systems would be operating at a steady state. The anticipated hourly emissions are shown in **AIR QUALITY Table 6**.

In order to determine maximum emissions over the course of one typical day or year, it is necessary to examine various startup scenarios in combination with shutdown and normal operation. Assumptions must be made about the frequency of startups or shutdowns although it is impossible to exactly define how often startups will occur. The assumptions leading to the estimates of daily and annual emissions are illustrated above. It is assumed that both CTGs could startup simultaneously.

AIR QUALITY Table 6
BEP II, Hourly Operational Emissions (lb/hr)

Operational Source – Mode	NOx (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)	SO_2 (lb/hr)	VOC (lb/hr)
Each CTG/HRSG (@ 20ºF, 80% w/o duct burning)	14.8	6.5	18.0	2.7	4.1
Each CTG/HRSG (@ 20ºF, 100% w/o duct burning)	18.4	6.6	22.4	3.4	5.2
Each CTG/HRSG (@ 59ºF, 80% w/o duct burning)	13.6	6.5	16.6	2.5	3.8
Each CTG/HRSG (@ 59ºF, 100% w/o duct burning)	16.9	6.6	20.5	3.1	4.7
Each CTG/HRSG (@ 59ºF, 100% w/ duct burning)	18.0	7.6	33.2	3.2	6.8
Each CTG/HRSG (@ 95ºF, 80% w/o duct burning)	12.5	6.4	15.2	2.3	3.5
Each CTG/HRSG (@ 95ºF, 100% w/o duct burning)	15.4	6.5	18.7	2.9	4.3
Each CTG/HRSG (@ 95ºF, 100% w/ duct burning)	16.5	7.5	31.3	3.0	6.4
Cooling Tower (8 cells)	---	3.6	---	---	---
Cooling Tower for Inlet Air Chillers (4 cells)	---	0.7	---	---	---
Fire Pump Engine	4.6	0.3	5.7	0.1	0.7

Source: BEP II 2002d, AFC Appendix 7.7-A, Siemens Westinghouse estimated emissions; and independent staff assessment for cooling towers.

Note: According to the AFC supplement in July 2003, the inlet air chillers would not alter the estimated CTG/HRSG emission estimates.

AIR QUALITY Table 7 summarizes the estimated maximum daily emissions from the project.

AIR QUALITY Table 7
BEP II, Maximum Daily Operational Emissions (lb/day)

Operational Source	NO_x (lb/day)	PM_{10} (lb/day)	CO (lb/day)	SO_2 (lb/day)	VOC (lb/day)
CTG/HRSG #3	2,881	144	1,904	65	119.5
CTG/HRSG #4	2,881	144	1,904	65	119.5
Cooling Tower (8 cells)	---	86.2	---	---	---
Cooling Tower for Inlet Air Chillers (4 cells)	---	16.7	---	---	---
Fire Pump Engine	4.6	0.3	5.7	0.1	0.7
TOTAL	**5,767**	**391**	**3,814**	**130**	**240**

Source: BEP II 2002d, AFC Table 7.7-11, p. 7.7-8; and independent staff assessment for cooling towers.

AIR QUALITY Table 8 summarizes the maximum annual emissions from the project based on the assumptions provided above and the emission rates outlined in the AFC.

Ammonia Emissions

Due to the large combustion turbines used in this project and the need to control NOx emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix with the flue gases to reduce NOx; a portion of the ammonia will pass through the SCR and will be emitted unaltered, out the stacks. These ammonia emissions are known as ammonia slip. The applicant has proposed achieving an ammonia slip no greater than 10 ppm. The applicant calculated the maximum emissions of ammonia to be approximately 33 pounds per hour per CTG/HRSG (BEP II 2002d, AFC Appendix 7.7-A). Staff anticipates that ammonia

AIR QUALITY Table 8
BEP II, Estimated Annual Operational Emissions (tons per year, tpy)

Operational Source	NO_x (tpy)	PM_{10} (tpy)	CO (tpy)	SO_2 (tpy)	VOC (tpy)
CTG/HRSG #3 (a)	95.5	26.3	145.4	11.5	12.7
CTG/HRSG #4 (a)	95.5	26.3	145.4	11.5	12.7
Cooling Tower (8 cells)	---	15.7	---	---	---
Cooling Tower for Inlet Air Chillers (4 cells)	---	3.1	---	---	---
Fire Pump Engine	0.12	0.01	0.15	0.01	0.02
TOTAL	**191**	**71**	**291**	**23**	**25**

Source: BEP II 2002d, AFC Appendix 7.7-A, and Table 7.7-12, p. 7.7-8; and independent staff assessment for cooling towers.

slip levels below 5 ppm would be achievable on a routine basis with proper operation and well-maintained equipment, for example with fresh catalyst surfaces.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time frame between the completion of the construction and the reliable production of electricity for sale on the market. Normally, during the initial testing during commissioning the post-combustion control systems (the SCR system) may not be fully installed or operational.

The applicant identified the series of tests (BEP II 2002d, AFC Appendix 7.7-N) that would result in greater-than-routine emissions as each unit is commissioned. The sequence of commissioning would be as follows: 1) minimum fuel flow tests (1 day); 2) first fire (2 days); 3) generator protection tests (2 days); 4) initial synchronization (1 day); 5) diffusion burners (3 days); 6) changeover tests (2 days); and 7) premix burners (8 days). These tests would require approximately 300 hours of operations over approximately a two- to four-month period.

Emissions of all pollutants other than NOx and CO would be similar during commissioning to those that would occur under routine conditions. As such, the impacts analysis for initial commissioning only considers NOx and CO for short-term periods. The emissions anticipated by the applicant for the commissioning period are summarized in **AIR QUALITY Table 9**.

Staff anticipates that the applicant would minimize commissioning emissions by limiting the time of each commissioning activity to the shortest duration feasible, consistent with manufacturer’s recommendations, because emissions occurring during commissioning would accrue towards the annual limitations imposed by the MDAQMD.

AIR QUALITY Table 9
BEP II, Proposed NOx and CO Commissioning Emissions

Commissioning Sources	Pollutant, Averaging Time	Maximum Emissions
CTG/HRSG #3 and #4	NOx, hourly	1,671 lb/hr
	NOx, daily	22,000 lb/day
	CO, hourly	2,974 lb/hr
	CO, daily	44,000 lb/day

Source: BEP II 2002d, AFC Table 7.7-39.

PROJECT IMPACTS

MODELING APPROACH

Air dispersion modeling provides a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. The models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for representative ambient meteorological conditions. Model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$). They are an estimate of the concentration of the pollutant emitted by the project that will occur at ground level.

Inputs for the modeling analysis include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Southern California Edison (SoCal) service center near Blythe for the years 1989 through 1993. Upper air data from Desert Rock, Nevada, approximately 30 miles west of Las Vegas, was also used with the local surface data to form the dispersion model meteorology input file.

The applicant used a regulatory-guideline model approved by the U.S. EPA (Industrial Source Complex, Short-Term, ISCST3 Version 00101) to estimate the impacts of project-related NOx, PM_{10}, CO and SOx emissions. Additionally, the applicant used the Fugitive Dust Model (FDM) for construction fugitive dust emissions. A description of the modeling analysis for operational activities is provided in AFC Section 7.7.8.5, for construction activities is provided in AFC Section 7.7.8.7, and for commissioning activities is provided in AFC Section 7.7.8.10 (BEP II 2002d).

For the 1-hour impacts of NO_2, the applicant provided a refined modeling analysis of NOx using the ozone limiting method (ISC3_OLM, version 96113). This method calculates the maximum NO to NO_2 conversion using ozone concentration files (from Blythe in 1991 and 1992) to determine maximum 1-hour NO_2 concentrations assuming that 10 percent of the exhaust NOx is NO_2 and that, over time, the available ozone allows a 100 percent conversion of the remaining NO to NO_2. This method conservatively predicts high levels NO_2 concentrations because it does not consider mixing or the quantities of ozone consumed in the reaction. The OLM is a method accepted by the U.S. EPA and CARB for 1-hour NO_2 modeling.

The applicant's modeled impacts were added to the available highest ambient background concentrations measured during 1996 to 2002 at the nearest monitoring station (see **AIR QUALITY Table 3** above). Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or contribute to an existing violation.

CONSTRUCTION IMPACTS

The applicant provided staff with a modeling analysis of the impacts caused by the construction-related emissions. The modeling incorporates the applicant's construction mitigation measures. Staff reviewed the applicant's modeling analysis and supporting information and concludes that it is adequate.

The results of the construction impacts analyses are presented in **AIR QUALITY Table 10**. The values in **bold** represent values that equal or exceed the relevant air quality standard. Without any project-related impacts, existing background conditions for PM_{10} exceed the state standard.

AIR QUALITY Table 10
BEP II, Ambient Air Quality Impacts from Construction (µg/m^3)

Pollutant	Averaging Period	Project Impact	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM_{10} (a)	24-hour	**62.87**	**84**	**147**	50	CAAQS	**294**
	Annual	8.52	**24**	**33**	20	CAAQS	**163**
NO_2 (b)	1-hour	146.7	70	217	470	CAAQS	46
	Annual	10.2	11	22	100	NAAQS	22
CO	1-hour	27.8	2,300	2,328	23,000	CAAQS	10
	8-hour	15.7	1,456	1,471	10,000	NAAQS	15
SO_2	1-hour	4.77	21.0	26	655	CAAQS	4
	3-hour	3.83	21.0	25	1,300	NAAQS	2
	24-hour	1.81	10.5	12	105	CAAQS	12
	Annual	0.37	2.6	3	80	NAAQS	4

Source: BEP II 2002d, AFC Table 7.7-36 and 37, and Appendix 7.7-K and 7.7-L.

(a) Fugitive dust emissions based on applicant analysis using FDM.

(b) NO_2 impacts based on ISC3-OLM analysis.

As indicated in **AIR QUALITY Table 10**, the project construction activities would further exacerbate existing violations of the state PM_{10} standards, and thus constitute a significant air quality impact for PM_{10}. Additionally, NOx and VOC emissions from construction equipment would react to contribute to existing violations of the ozone standards and thus would constitute a significant air quality impact for ozone via ozone precursors. The project's construction activities would not create a new violation of either NO_2, CO, or SO_2 air quality standards, thus impacts from NO_2, CO, and SO_2 emissions are not considered significant.

OPERATION IMPACTS

The following section discusses the ambient air quality impacts that could occur during routine operation throughout the life of the project, including initial commissioning.

Routine Operation Impacts

A refined modeling analysis was performed to identify off-site criteria pollutant impacts from routine operational emissions. Since BEP II is considered a major modification to BEP I, the impact analysis included BEP II emissions and combined emissions from BEP I and BEP II. The impact modeling analysis included startup/shutdown scenarios to determine maximum short-term and annual emission impacts. Short-term emission rates in the model are derived from startup conditions for the combustion turbines, with simultaneous testing of the emergency fire pump engine. Annual emission rates in the model are derived from full-time, full-load operation of the combustion turbines with approximately 400 hours annually in either a startup or shutdown mode and only 72 hours annually of downtime. Staff analyzed the project assuming that PM_{10} emission rates for the cooling tower sources, including inlet chillers, reflect staff's opinion that 100 percent of cooling tower drift converts to PM_{10}.

The predicted concentrations of the nonreactive pollutants for BEP II and BEP II with BEP I are summarized in **AIR QUALITY Tables 11 and 12**, respectively. The values in bold in the impacts and background columns represent values that equal or exceed the relevant air quality standard. Without any project-related impacts, existing background conditions for PM_{10} exceed the state standard.

AIR QUALITY Table 11
BEP II, Ambient Air Quality Impacts from Routine Operation (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM_{10}	24-hour	6.19	**84**	**90**	50	CAAQS	**180**
	Annual	0.40	**24**	**24**	20	CAAQS	**122**
NO_2	1-hour (b)	182	70	252	470	CAAQS	54
	Annual	0.29	11	12	100	NAAQS	12
CO	1-hour	153	2,300	2,453	23,000	CAAQS	11
	8-hour	28	1,456	1,484	10,000	NAAQS	15
SO_2	1-hour	12.2	21.0	33	655	CAAQS	5
	3-hour	5.97	21.0	27	1,300	NAAQS	2
	24-hour	0.77	10.5	11	105	CAAQS	11
	Annual	0.02	2.6	3	80	NAAQS	3

Source: BEP II 2002d, AFC Table 7.7-32; with independent staff assessment for PM_{10} emissions from chillers and cooling towers.

(a) All results include fire water pump engine testing and gas turbine startups as part of routine operation.

(b) NO_2 impacts based on ISC3-OLM analysis with CTGs achieving 2.5 ppm (1-hour).

The modeling results indicate that the project's operational impacts would not create violations of NO_2, CO, or SO_2 standards, but could further exacerbate existing violations of the state PM_{10} standard. In light of the existing PM_{10} non-attainment status for the region, the impacts of direct PM_{10} emissions are considered to be significant and warrant additional mitigation. Secondary impacts caused by reaction of PM_{10} and ozone precursors are also discussed below.

There is also a potential for $PM_{2.5}$ impacts to occur because the project would also emit this contaminant and precursors. The magnitude of potential $PM_{2.5}$ impacts are not quantified here because there is not an established methodology for quantifying $PM_{2.5}$ emissions from every source and because there is no established method for characterizing the complex interaction of $PM_{2.5}$ precursors in the ambient air. $PM_{2.5}$ mitigation could be provided by mitigating combustion-related PM_{10}, which includes $PM_{2.5}$, and mitigating reactive precursor emissions that can lead to $PM_{2.5}$.

AIR QUALITY Table 12
BEP II with BEP I, Ambient Air Quality Impacts from Routine Operation (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM_{10}	24-hour	13.03	**84**	**97**	50	CAAQS	**194**
	Annual	2.19	**24**	**26**	20	CAAQS	**131**
NO_2	1-hour (b)	183	70	253	470	CAAQS	54
	Annual	0.7	11	12	100	NAAQS	12
CO	1-hour	204	2,300	2,504	23,000	CAAQS	11
	8-hour	80	1,456	1,536	10,000	NAAQS	15
SO_2	1-hour	12.2	21.0	33	655	CAAQS	5
	3-hour	6.1	21.0	27	1,300	NAAQS	2
	24-hour	0.83	10.5	11	105	CAAQS	11
	Annual	0.04	2.6	3	80	NAAQS	3

Source: BEP II 2002d, AFC Table 7.7-33-A; with independent staff assessment for PM_{10} emissions from chillers and cooling towers.

(a) All results include fire water pump engine testing and gas turbine startups as part of routine operation.

(b) NO_2 impacts based on ISC3-OLM analysis with CTGs achieving 2.5 ppm (1-hour).

The highest modeled 1-hour NO_2 impact for BEP I and BEP II (183 µg/m^3) occurs during the unlikely occasion of testing of the diesel fire pump engines at both sites during one hour of simultaneous startup of all four CTGs. Without the diesel engines, the maximum 1-hour NO_2 impact during startups would be 173 µg/m^3, and the impacts during routine operation would be less. The location of the maximum impact would be near the property line immediately north of the BEP I site, and the maximum impact at the nearest rural residence, approximately 2,750 feet southwest of the BEP II power plant, would be approximately 105 µg/m^3.

The maximum 24-hour PM_{10} impact for BEP I and BEP II (13.03 µg/m^3) would occur near the BEP I site boundary, immediately north of the cooling tower. Because of the high buoyancy of the CTG and HRSG exhaust, the combustion turbine sources contribute little to the maximum impacts near the project site boundary. The chillers and cooling tower contribute to the elevated PM_{10} concentrations at the edge of the site. Maximum CTG and HRSG 24-hour PM_{10} impacts (less than 1 µg/m^3) occur about 0.75 miles (1.2 km) north and east of the site where the terrain rises about 20 meters above the base elevation of the plant. The 24-hour PM_{10} impacts from operation of all BEP I and BEP II sources at the nearest residences would be approximately 2 µg/m^3.

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, VOC, and ammonia are precursor pollutants that can contribute to the formation of secondary pollutants. Each of these can lead to secondary PM_{10}, and NOx and VOC are precursors to ozone. The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there are no agency-recommended models or procedures for estimating nitrate or sulfate formation. However, because of the known relationship of NOx and SO_2 emissions to secondary PM_{10} formation, it can be said that the emissions of NOx and SO_2 from the project do have the potential (if left unmitigated) to contribute to higher PM_{10} levels, and possibly $PM_{2.5}$, in the region.

As identified above, PM_{10} impacts would be significant due to direct emissions. Secondary impacts would be significant for PM_{10} and ozone because routine operational emissions of precursor pollutants would contribute to existing violations of the state-level PM_{10} and ozone standards. Along with mitigation that is appropriate to reduce significant, direct impacts of PM_{10}, additional mitigation for emissions of precursors is appropriate to reduce secondary impacts to PM_{10} and ozone. Mitigation for these pollutants would also help to reduce potential $PM_{2.5}$ impacts.

Impacts During Fumigation Conditions

There is the potential that higher short-term concentrations may occur during fumigation conditions. Fumigation conditions are generally short-term in nature and are only compared to 1-hour or 3-hour standards. The applicant analyzed the air quality impacts under fumigation conditions from the project turbine using the SCREEN3 model (Version 96043). For the fumigation modeling exercise, the applicant combined the emission rates from both CTG/HRSGs at BEP II and modeled them as if they were emitted from a single CTG/HRSG. All pollutants and normal operating conditions were examined. The fumigation impacts are shown in **AIR QUALITY Table 13**.

AIR QUALITY Table 13
BEP II with BEP I, Ambient Air Quality Impacts During Fumigation (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
NO_2	1-hour	112	70	182	470	CAAQS	39
CO	1-hour	47.6	2,300	2,348	23,000	CAAQS	10
SO_2	1-hour	10.7	21.0	31.7	655	CAAQS	5
	3-hour	9.7	21.0	30.7	1,300	NAAQS	2

Source: BEP II 2002d, AFC Table 7.7-38, and Appendix 7.7-M.

(a) All results include BEP II gas turbine startups as part of routine operation, with routine emissions from BEP I.

Impacts During Initial Commissioning

The applicant anticipates that commissioning activities would occur over approximately a two- to four-month period. Only NOx and CO impacts are analyzed here because these are the only criteria pollutants that will be elevated during the commissioning phase over levels that would occur under routine operations. The results of the applicant's modeling analysis are presented in **AIR QUALITY Table 14**.

Visibility Impacts

An analysis of the project's gaseous emissions impacts on long-range visibility is required under the Federal Prevention of Significant Deterioration (PSD) permitting program. The analysis includes the effects of gaseous emissions (primarily NOx and SO_2) and particulate (PM_{10} and $PM_{2.5}$) emissions on visibility impairment in the nearest Federally-designated Class I areas, which are generally national parks, national wildlife

AIR QUALITY Table 14
BEP II with BEP I, Ambient Air Quality Impacts During Commissioning ($\mu g/m^3$)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
NO_x	1-hour	205	70	275	470	CAAQS	59
	Annual	0.9	11	11.9	100	NAAQS	12
CO	1-hour	1,887	2,300	4,187	23,000	CAAQS	18
	8-hour	394	1,456	1,850	10,000	NAAQS	19

Source: BEP II 2002d, AFC Table 7.7-40, and Appendix 7.7-N.

(a) All results include BEP II gas turbine startups as part of routine operation, with routine emissions from BEP I.

refuges, and wilderness areas. The nearest Class I area to BEP II is Joshua Tree National Park, approximately 40 miles (65 km) to the northwest. The applicant used the U.S. EPA model CALPUFF to assess the project's visibility impacts. (This model was also used to determine nitrogen and sulfur deposition rates at the park.)

The results from the CALPUFF modeling analysis for BEP II indicate that the project's maximum impacts to visibility (percent change in light extinction) within the Joshua Tree National Park would be between 1.46 and 2.05 percent depending on the model year analyzed (BEP II 2003d). The analysis was conducted using monthly average relative humidity data. Although it was not required by the modeling protocol, a more refined analysis was also conducted using hourly relative humidity values. The results of the analyses, including the voluntary refined analysis, show impacts from BEP II would be below the established screening level value of five percent. The National Park Service protocol does not require existing sources from BEP I to be included in these analyses for BEP II. Staff however notes that including BEP I sources would result in an impact of approximately two-times the magnitude of BEP II, which would be less than the five percent screening level used by the National Park Service. The project's visibility impacts on Class I areas are therefore considered insignificant (NPS/Codding May 7, 2003).

MITIGATION

Applicant's Proposed Mitigation

Applicant's Construction Mitigation

MDAQMD Rule 403 requires the applicant to limit fugitive dust during the construction phase of a project. To comply with this rule and reduce construction impacts, the applicant proposed a pair of mitigation measures for fugitive dust and equipment exhaust emissions (BEP II 2002d, AFC p. 7.7-54). The applicant's measures include preparing a fugitive dust mitigation plan and requiring construction contractors to minimize emissions from equipment by limiting the idling time and properly maintaining the equipment. The emission estimates and modeling analysis in this assessment assume successful implementation of proposed dust control measures and modern, well-maintained equipment operating approximately 8 hours per day.

Applicant's Operations Mitigation

The BEP II design includes a combination of clean-fuel-firing equipment, emission control devices, and emission reduction credits. The equipment description, equipment operation, and emission control devices are provided in the **AIR QUALITY Project Description**.

Emission Controls

The combustion turbines would limit NOx formed during combustion using dry low-NOx combustors. Compared to steam or water-injection designs, combustors designed for low-NOx firing maintain low temperatures, thus minimizing NOx formation, while thermal efficiencies remain high.

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, a flue gas control system, including a catalyst system, will be installed in the HRSG. The applicant is proposing a selective catalytic reduction system to reduce NOx. The applicant investigated using an oxidizing catalyst system to reduce CO and VOC, but determined that it would not be cost effective and instead proposes to manage these pollutants by controlling the combustion process. The applicant's proposal would result in emissions being limited to 2.5 ppmvd NOx (1-hour average), with 10 ppmvd ammonia slip, between 5 and 8.4 ppmvd CO (3-hour average), and 1 ppmvd VOC (1-hour average). If combustion controls fail to achieve the regulatory limits, the plant design includes contingencies to allow future installation of an oxidation catalyst if necessary (BEP II 2002d, AFC p. 7.7-36).

The cooling towers of the steam-cycle cooling system and the inlet air chillers would use drift eliminators to minimize cooling tower drift to 0.0006 and 0.001 percent, respectively, which would minimize the accompanying PM_{10} emissions.

Emission Offsets

In addition to emission control strategies included in the project design, the applicant would provide emission reductions to offset emissions of PM_{10}, SOx, and ozone precursor pollutants (NOx and VOC). The applicant is required to offset these pollutants by MDAQMD Rule 1305 by obtaining and surrendering sufficient valid emission reduction credits (ERCs). The quantity of ERCs required by Rule 1305 and the quantity identified by BEP II are each shown in **AIR QUALITY Table 15**.

Confidential filings made by the applicant in April 2003 after publication of the PDOC indicate that the NOx ERCs identified above were issued by the MDAQMD in March 2003 (Galati 2003a). The NOx ERCs were created by reducing emissions from numerous large natural-gas fired sources near Blythe. Surplus NOx ERCs would be used to offset VOC emissions through an interpollutant trade. The U.S. EPA notes, however, that interpollutant trades require its approval on a case-by-case basis (U.S. EPA 2002a). Staff expects that the proposed trade of NOx ERCs for VOC emissions would be acceptable to the U.S. EPA because reductions of NOx are usually more valuable for ozone management than reductions of VOC.

AIR QUALITY Table 15
BEP II Emission Offset Requirements and ERC Sources

Offset Requirement, MDAQMD ERC Source	ERC Identification	NOx (tpy)	PM_{10} (tpy)	SOx (tpy)	VOC (tpy)
BEP I Offset Obligation		202	103		
BEP II Additional Offset Obligation		191	56	48	48
Total BEP II Offset Obligation		**393**	**159**	**48**	**48**
Shutdown of Biogen	MDAQMD – 0021	27*			
Transfer from SCAQMD	MDAQMD – 0024	175*			(281)*
Blythe Road Paving	MDAQMD – 0027		125*		
Transfer from SCAQMD	MDAQMD – 0045				39
CRIT Road Paving	MDAQMD (pending)		126		
Confidential Option Agreement	MDAQMD (pending)	250			
Total ERCs Identified:		**452**	**251**	**0**	**39**
Sufficient for MDAQMD Requirements?		Yes	Pending Validation	Yes, from PM_{10}	Yes, from NOx

Source: MDAQMD 2002a. PDOC, Tables 7 and 8.

Notes:

MDAQMD allows surplus NOx offsets to satisfy VOC obligation, and surplus PM10 to satisfy SOx obligation (at 1.0-to-1.0 interpollutant trading ratio.

Offsets marked in (parenthesis) were obtained and converted with an interpollutant trade to create usable ERCs.

Offsets marked with an asterisk * were applied to the BEP I offset obligation and would be used in combination with new offsets to satisfy the total BEP II obligation.

The offsets are incomplete because the ERCs that would be used to offset PM_{10} and SOx have not yet been approved. The U.S. EPA has indicated that the road paving ERCs would be invalid and that the MDAQMD must require the applicant to obtain different PM_{10} ERCs before issuing the FDOC (U.S. EPA 2002a). However, based on the applicant's more-recent filings (Galati 2003a), no alternative ERCs have been identified. It is not yet clear whether the MDAQMD concurs with the U.S. EPA's requirement for alternative ERCs. Additionally, it is not clear whether the EPA would accept the proposed interpollutant trade of road paving PM_{10} ERCs for SOx emissions. If valid ERCs and interpollutant trading ratios are approved by the MDAQMD, the applicant's ERC acquisitions would enable compliance with MDAQMD offset requirements. The ERC acquisitions would also be used as the applicant's proposed strategy for mitigation under the California Environmental Quality Act (CEQA).

Adequacy of Proposed Mitigation

Adequacy of Construction Mitigation

The effectiveness of the proposed construction mitigation can be expressed by the percentage of uncontrolled emissions that are avoided, and it varies widely due to the number of influencing factors. Some of these factors include: ambient conditions (temperature, wind, and humidity), size and weight of vehicles, vehicle speed, frequency and number of active vehicles, soil characteristics (chemical composition, particle size distribution, organic components), and day-to-day aggressiveness of mitigation efforts (e.g., application of water or dust suppressants, street sweeping to remove carryout from paved roads). If the mitigation measures for fugitive dust-generating activities are applied correctly and with sufficient frequency, the control efficiency can approach 100 percent. Much of the uncertainty is due to varying degrees of vigilance on the part of construction personnel. The applicant presents an analysis of probable impacts that presumes an average fugitive dust mitigation efficiency. The effectiveness of proposed mitigation for construction equipment emissions also depends largely on the vigilance of construction personnel to operate equipment properly.

As shown in **AIR QUALITY Table 12** above, direct impacts of NO_2, CO, and SO_2 would not be significant. Direct PM_{10} impacts would be reduced by the proposed mitigation but would remain significant because any increase to PM_{10} concentrations could contribute to continuing violations of the PM_{10} standards. Similarly, secondary impacts for PM_{10} and ozone would continue to be significant because of construction emissions of PM_{10} and ozone precursors. Additional mitigation is necessary (see **Staff Proposed Mitigation**) to reduce direct PM_{10} impacts and secondary impacts to PM_{10} and ozone.

Adequacy of Operations Mitigation

Staff is concerned that the MDAQMD BACT determination in the PDOC for gas turbine emissions of NOx and CO are inconsistent with current U.S. EPA and CARB recommendations. Recommendations from U.S. EPA on this and other recent Energy Commission cases indicate that 2.0 ppmvd is achievable for NOx on a 1-hour basis (U.S. EPA 2002a, CARB 2002a). The CO requirement does not conform with CARB recommendations, which indicate that 6.0 ppmvd is achievable for all modes of operation on a 3-hour basis (CARB 2002a). Similar recent projects, for example the Palomar Energy Project and Tesla Power Project, before the Energy Commission are committed to achieving BACT levels of 2.0 ppmvd NOx (1-hour) and 4.0 ppmvd CO (3-hour). Similarly, the PDOC requirement for ammonia slip is inconsistent with recommendations from U.S. EPA (U.S. EPA 2002a) and CARB (CARB 1999). These agencies indicate that the more-stringent ammonia slip level of 5 ppmvd is achievable, and Energy Commission staff agrees (CEC 2002a). The PDOC needs to be changed if the MDAQMD agrees with these positions. As such, additional control may ultimately be necessary to satisfy LORS, which would improve the applicant’s mitigation strategy.

Direct PM_{10} Mitigation

According to the U.S. EPA comments on the PDOC, the road paving PM_{10} ERCs identified in the PDOC do not satisfy their fundamental requirements for offsets to be surplus, quantifiable, permanent, and federally enforceable. U.S. EPA also notes that they would need to approve any interpollutant trades on a case-by-case basis (U.S. EPA 2002a). Because the proposed road paving ERCs may be invalid, additional mitigation is required to ensure that project PM_{10} emissions would be adequately offset.

Secondary PM_{10} Mitigation

It is difficult to correlate the effect of gaseous emissions on particulate formation because of the complexity of the precursor reactions. Because MDAQMD requires offsets for project emissions of NOx and SOx, staff expects that compliance with the offset requirements would satisfactorily mitigate the effects of these precursors as long as the interpollutant trades are approved by the U.S. EPA. Additional mitigation is required to ensure that project emissions of ammonia would cause insignificant impacts to secondary PM_{10} and $PM_{2.5}$ formation.

Secondary Ozone Mitigation

The applicant proposes providing offsets of NOx to mitigate secondary ozone impacts. The ability of the offsets to mitigate project ozone impacts depends on whether sufficient combined reductions of NOx and VOC (precursor organic compounds) would occur. Although the applicant (Galati 2003a) and the PDOC (MDAQMD 2002a) identify that a sufficient quantity of NOx ERCs would be surrendered, see **AIR QUALITY Table 15** above, the package depends on an interpollutant trade of NOx ERCs to offset VOC. This interpollutant trade would need a case-by-case U.S. EPA approval (U.S. EPA 2002a). Because the proposed interpollutant trade has not yet been approved by the U.S. EPA, additional mitigation is required to ensure that project emissions of ozone precursors would be adequately offset.

Staff Proposed Mitigation

Staff Proposed Construction Mitigation

Staff proposes specific mitigation to reduce construction emissions of PM_{10}, VOC, and NOx to avoid PM_{10} and ozone impacts. Much of the uncertainty in the effectiveness of the applicant's proposed strategy for construction mitigation is due to varying degrees of vigilance on the part of construction personnel. Coordination of the measures would be by personnel specifically approved by the Energy Commission as the Construction Mitigation Manager (**AQ-SC1**). Staff's proposed Conditions of Certification **AQ-SC2** and **AQ-SC3** would require the applicant to prepare and adhere to a Construction Mitigation Plan. Because SO_2 is also a precursor to PM_{10}, one aspect of the plan would require use of ultra-low sulfur diesel fuel. In order to confirm implementation of these plans, staff proposes reporting and monitoring of certain environmental parameters (**AQ-SC3** and **AQ-SC4**) that would be used to indicate whether a high degree of day-to-day vigilance is being maintained.

With the implementation of the staff-recommended construction mitigation measures, the PM_{10} and ozone impacts from the construction of BEP II can be reduced to a level of insignificance.

Staff Proposed Operations Mitigation

The U.S. EPA believes that the proposed road paving PM_{10} ERCs would be invalid and that they would need to approve any interpollutant trades for PM_{10} or ozone precursors on a case-by-case basis (U.S. EPA 2002a). Mitigation of direct PM_{10} impacts depends directly on the validity of ERCs from road paving, and mitigation of secondary ozone and PM_{10} impacts depends directly on the validity of interpollutant trades of ERCs. Given the concerns set forth by U.S. EPA, staff does not yet consider the applicant's proposed mitigation to be viable. Before the roads are paved and ERCs are issued by MDAQMD, staff believes that the applicant and MDAQMD need to demonstrate that the road paving strategies would satisfy the concerns raised by U.S. EPA and eventually result in valid PM_{10} ERCs. If the ERCs can be validated as proposed, staff would include in the Final Staff Assessment a discussion of the effectiveness of the offsets as mitigation for project emissions and identify additional mitigation if necessary. To mitigate PM_{10} and ozone impacts with ERCs, staff recommends a condition (**AQ-SC6**) to assure that proper offsets will be acquired. Note that this condition would need to be revised in the Final Staff Assessment depending on the validity of the road paving PM_{10} ERCs and the interpollutant trades.

Mitigation of secondary PM_{10} impacts also depends partially on managing ammonia emissions. The ammonia slip that would be in the exhaust after passing through the SCR catalyst system could react with SOx and NOx in the ambient air to form ammonium sulfate and ammonium nitrate, which are components of PM_{10} and $PM_{2.5}$. As proposed, BEP II would contribute between 200 and 300 tons per year of ammonia. The reactivity can be enhanced with available nitrate and sulfate precursors, high humidity, and mild ambient temperatures. Because there are few sources of SOx and NOx near Blythe and because periods of high humidity are extremely rare in Blythe, staff expects only a weak tendency for secondary particulate matter to form from project ammonia emissions. Mild temperatures enhancing ammonia-to-particulate conversion would generally occur during the winter months, when $PM_{2.5}$ concentrations in the desert tend to be higher (CARB 2001). Although staff does not anticipate a strong correlation between the project's ammonia emissions and ambient particulate impacts, staff does expect that the applicant will control its ammonia slip emissions to the extent feasible, while maintaining the required NOx emission limit, to reduce the operational costs of ammonia loss.

Energy Commission staff experience, guidance from agencies with oversight authority (U.S. EPA 2002a), and vendor guarantees show that ammonia slip below 5 ppmvd at 15% O_2 is achievable (CARB 1999). Because the project as proposed would only achieve an ammonia slip limit of 10 ppm, it would not be consistent with U.S. EPA or CARB recommendations. It is also possible that increased ammonia emissions could under certain circumstances contribute to increased secondary PM_{10} and $PM_{2.5}$ concentrations. Staff recommends mitigation (**AQ-SC8**) that would require the project to achieve 5 ppmvd ammonia slip to address this impact.

CUMULATIVE IMPACTS

The cumulative impact analysis identifies any stationary sources within a 6-mile radius of the project that could interact with the project's emissions. These include any source that will soon be or was in the permitting process at the time, or that had received a construction permit from the MDAQMD but was not yet operational. Emissions from other existing stationary sources within the 6-mile radius are normally presumed to be included in the existing background air quality conditions. Sources beyond the 6-mile radius are presumed to cause minimal effects at the project site.

The applicant found no sources in the area that fit these criteria (BEP II 2002d, AFC p. 7.7-46). The area was also investigated for other large sources, such as large stationary internal combustion engines for agricultural purposes, and none were found. The Southern California Gas Compressor Station in Blythe was voluntarily included by the applicant in their modeling analysis although it does not fit the criteria for being a cumulative project. It is worth noting that recent modifications at the compressor station would reduce emissions from that source compared to historic conditions. The modeling analyses for BEP II included BEP I, and these results are presented in **AIR QUALITY Table 12**, above.

A new 500 kV transmission line is currently being proposed by the Imperial Irrigation District (IID) that would connect the transmission system in Blythe to the Devers Substation near Palm Springs. This is a project that should be considered in staff's cumulative analysis. The new transmission line would not include any permanent, stationary sources of air pollution. Therefore, including it in the cumulative air quality assessment for BEP II does not affect the results presented in **AIR QUALITY Table 12**. Construction emissions caused by the IID project would be short-term and would be distributed over the 118-mile length of the project. As such, they would not be expected to substantially overlap with BEP II project emissions. To address the cumulative impacts, Energy Commission staff provided a letter to IID July 2, 2003 with recommendations for IID to incorporate specific construction-related mitigation measures.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is more than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this PSA). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

The air quality analysis for ozone and PM_{10} impacts depends on an offset package that has not yet been reviewed or approved by the MDAQMD or the U.S. EPA. If the final mitigation recommended by staff is not acceptable to the applicant, the impacts could remain partially unmitigated and environmental justice may need to be further evaluated.

COMPLIANCE WITH LORS

FEDERAL

The U.S. EPA is responsible for completing the Federal Prevention of Significant Deterioration (PSD) review requirements. Review under the PSD program has not been completed by U.S. EPA. It is possible that changes to the project proposal may be necessary to meet federal requirements, and that these changes could occur after the Energy Commission siting process. To achieve compliance with the PSD program, the project must satisfy requirements for BACT, defined by the U.S. EPA. Although the U.S. EPA has not formally released a determination of PSD requirements, their comments on the District's PDOC indicate that BEP II does not presently satisfy BACT requirements.

Because the federal permitting process is ongoing, and there remains the potential for project revisions, staff recommends a condition of certification for coordinating future possible modifications (**AQ-SC5**).

Without formal U.S. EPA involvement, staff cannot make a recommendation, at this time, as to whether the project is in compliance with PSD requirements.

STATE

Staff believes that if the project meets the U.S. EPA recommendations for offsets and BACT, the project would demonstrate compliance with California State Health and Safety Code, Section 41700.

LOCAL

The MDAQMD completed a Preliminary Determination of Compliance (PDOC, MDAQMD 2002a) for this project dated November 14, 2002, with a 30-day public comment period. Although the PDOC indicates that BEP II would comply with all applicable District requirements, the U.S. EPA, CARB, and Energy Commission staff submitted comments to the District requesting numerous revisions and clarifications on the PDOC. It is not yet clear whether these requests will be fulfilled by the District.

The U.S. EPA and CARB comments on the PDOC (U.S. EPA 2002a and CARB 2002a) request that revisions be made to the BACT determination. The agencies also are concerned about cooling tower emission limitations, the validity of PM_{10} offsets from road paving, interpollutant trading of offsets, and exemption of malfunctions.

Energy Commission staff also notes that it may not be possible for the project equipment to achieve the startup and shutdown emission levels proposed by the applicant (in **AIR QUALITY Table 5**, above) for CO. This is based on staff experience reviewing preliminary CO data from the continuous emissions monitors at BEP I. This would require an additional revision to the PDOC and its emission limits related to startup and shutdown periods.

The requested revisions would need to be made to the Final Determination of Compliance (FDOC) before Energy Commission staff could agree that the project would be likely to comply with District requirements. The present likelihood of the project to comply with the District requirements is described below.

RULE 1302 – PROCEDURES, NEW SOURCE REVIEW, OFFSETS

Unsatisfactory offsets were identified at the time of the PDOC. According to the U.S. EPA comments on the PDOC, the road paving credits identified in the PDOC do not satisfy their fundamental requirements for offsets to be surplus, quantifiable, permanent, and federally enforceable. U.S. EPA also notes that they would need to approve any interpollutant trades on a case-by-case basis. The most recent confidential filing related to offsets indicates that road paving and interpollutant trades continue to be part of the strategy (Galati 2003a). It is not clear whether BEP II would be likely to comply with the offset requirements.

RULE 1303 – REQUIREMENTS, NEW SOURCE REVIEW, BACT

The BACT determination in the PDOC is not consistent with U.S. EPA requirements. According to the U.S. EPA, the NOx limit for the CTG/HRSGs must be revised in the FDOC to 2.0 ppmvd on a 1-hour basis. The U.S. EPA also strongly recommends that the ammonia slip limit be reduced from 10 ppmvd to 5 ppmvd on a 3-hour basis. The comments from CARB also indicate that the BACT determination for the equipment should be 2.0 ppmvd NOx (1-hour) and 6 ppmvd CO (3-hour). BEP II, as proposed, would not be likely to comply with the U.S. EPA BACT determination.

FACILITY CLOSURE

Eventually, BEP II will close, either as a result of the end of its useful life, or through some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease, and impacts associated with those emissions would no longer occur. The only other expected emissions would be construction/demolition emissions from the dismantling activities. Staff recommends that a Facility Closure Plan be submitted to the Energy Commission Compliance Project Manager to demonstrate compliance with all local, state, and federal rules and regulations during closure and demolition.

CONCLUSIONS AND RECOMMENDATIONS

The MDAQMD needs to eventually issue a Final Determination of Compliance (FDOC). The U.S. EPA and CARB requested that many changes be included in the MDAQMD's FDOC, and it is not yet clear whether MDAQMD will implement all of the requests made by these oversight agencies. It is not clear whether BEP II would be likely to comply with requirements for BACT because the determination made by MDAQMD is inconsistent with U.S. EPA and CARB recommendations. The FDOC should include revised BACT limits, revised limits during startup and shutdown periods, and new conditions addressing the inlet air chillers that were added by the applicant in July 2003.

The U.S. EPA believes that the offset strategy for PM_{10} is invalid and that special case-by-case approval of the offset interpollutant trading scheme is required. If these concerns are not addressed before the MDAQMD issues the FDOC, additional mitigation may be necessary to address project-related impacts to PM_{10} and ozone from precursor emissions. Because the offset strategy is incomplete, staff cannot determine whether BEP II would be likely to comply with MDAQMD offset rules or whether impacts to PM_{10} and ozone would be mitigated to a level of insignificance.

Staff has also requested information on two issues relevant to the Soil & Water analysis (organic components in the cooling water and wind erosion control of WCOP lands). Without implementation of appropriate soil conservation practices on the fallowed lands, staff may need to develop additional measures to control wind erosion and any associated PM_{10} emissions. The Final Staff Assessment will characterize the air quality effects of these issues based on any new information that may come as a result of the Soil & Water analysis.Before the Final Staff Assessment can be completed, the issues identified above must be resolved. The MDAQMD must issue an FDOC with a valid offset strategy and a BACT determination consistent with recommendations from oversight agencies. Based on the final offset strategy, staff would need to refine the recommended mitigation measures. Upon resolution of these issues, staff would recommend the following Conditions of Certification to address the impacts related to construction and operation of BEP II.

CONDITIONS OF CERTIFICATION

STAFF CONSTRUCTION CONDITIONS

AQ-SC1 The project owner shall designate and retain an on-site Air Quality Construction Mitigation Manager (AQCMM) who shall be responsible for directing and documenting compliance with Conditions **AQ-SC2** through **AQ-SC4** below for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more air quality construction mitigation monitors. The AQCMM shall have full access to areas of construction of the project site and linear facilities, and shall have the authority to appeal to the CPM to have the CPM stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the CPM.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and any air quality construction mitigation monitors. The AQCMM and all delegated monitors must be approved by the CPM before the start of ground disturbance.

AQ-SC2 The project owner shall provide an Air Quality Construction Mitigation Plan (AQCMP), for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with Conditions **AQ-SC3** and **AQ-SC4** below.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt.

AQ-SC3 The AQCMM shall submit to the CPM, in the Monthly Compliance Report (MCR), a construction mitigation report that demonstrates compliance with the following mitigation measures for the purpose of preventing all fugitive dust from leaving the project site:

a) All unpaved roads and disturbed areas in the project and linear construction sites shall be watered as frequently as necessary to comply with the dust mitigation objectives of Condition **AQ-SC4** (the prevention of fugitive dust plumes). The frequency of watering can be reduced or eliminated during periods of precipitation.

b) No vehicle shall exceed 10 miles per hour within the construction site.

c) The construction site entrances shall be posted with visible speed limit signs.

d) All construction vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

e) Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

f) All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

g) All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

h) Construction areas adjacent to any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan to prevent run-off to roadways.

i) All paved roads within the construction site shall be swept least twice daily (or less during periods of precipitation) to prevent the accumulation of dirt and debris.

j) At least the first 500 feet of any public roadway exiting from the construction site shall be swept least twice daily (or less during periods of precipitation) to prevent the accumulation of dirt and debris.

k) All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

l) All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

m) Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

n) Diesel-Fueled Engines

   (1) All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

   (2) All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

   (3) All construction diesel engines, which have a rating of 100 hp or more, shall meet, at a minimum, the Tier 1 California Emission Standards for Off-Road Compression-Ignition Engines as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless certified by the on-site AQCMM that a certified engine is not available for a particular item of equipment. In the event a Tier 1 ARB/U.S. EPA certified engine is not available for any off-road engine larger than 100 hp, that engine shall be equipped with a catalyzed diesel particulate filter (soot filter), unless

certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is “not practical” if, among other reasons:

a. there is no available soot filter that has been certified by either the California Air Resources Board or U.S. Environmental Protection Agency for the engine in question; or

b. the construction equipment is intended to be on-site for ten (10) days or less.

The CPM may grant relief from this requirement if the AQCMM can demonstrate that they have made a good faith effort to comply with this requirement and that compliance is not possible.

The use of a soot filter may be terminated immediately if one of the following conditions exists, provided that the CPM is informed within ten (10) working days of the termination:

a. The use of the soot filter is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or reduced power output due to an excessive increase in backpressure.

b. The soot filter is causing or is reasonably expected to cause significant engine damage.

c. The soot filter is causing or is reasonably expected to cause a significant risk to workers or the public.

d. Any other seriously detrimental cause which has the approval of the CPM prior to the termination being implemented.

(4) All heavy earthmoving equipment and heavy duty construction related trucks shall be properly maintained and the engines tuned to the engine manufacturer’s specifications.

(5) All heavy construction equipment shall not remain running at idle for more than five minutes, to the extent practical.

<u>Verification:</u> The project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of all diesel fuel purchase records, (3) copies of any complaints filed with the air district in relation to project construction, (4) a list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained, and (5) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition.

AQ-SC4 The AQCMM shall continuously monitor the construction activities for visible dust plumes. Observations of visible dust plumes, especially those beyond the project fenceline, indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMM shall implement the following procedures for additional mitigation measures in the event that visible dust plumes are observed:

a) The AQCMM shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

b) The AQCMM shall direct implementation of additional methods of dust suppression if step a) specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

c) The AQCMM shall direct a temporary shutdown of the activity causing the emissions if step b) specified above fails to result in adequate mitigation within one hour of the original determination. The activity shall not restart until one full hour after the shutdown. The owner/operator may appeal to the CPM any directive from the AQCMM to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMP shall include a section detailing how the AQCMM will effect the necessary changes in the construction activities within the time limits detailed here.

AQ-SC5 The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. EPA, and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-SC6 The project shall surrender the emission offset credits listed below or a modified list, as allowed by this condition, at the time that surrender is required by condition **AQ-18**. The project owner may request CPM approval for any substitutions or modification of credits listed below.

MDAQMD ERC Source	ERC Identification	NOx (tpy)	PM_{10} (tpy)	SOx (tpy)	VOC (tpy)
Shutdown of Biogen	MDAQMD – 0021	27*			
Transfer from SCAQMD	MDAQMD – 0024	175*			(281)*
Blythe Road Paving	MDAQMD – 0027		125*		
Transfer from SCAQMD	MDAQMD – 0045				39
CRIT Road Paving	MDAQMD (pending)		126		
Confidential Option Agreement	MDAQMD (pending)	250			

Notes: Offsets marked in (parenthesis) were obtained and converted with an interpollutant trade to create usable ERCs.

Offsets marked with an asterisk * were applied to the BEP I offset obligation and would be used in combination with new offsets to satisfy the total BEP II obligation.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, the requested change(s) clearly will not cause the project to result in a significant environmental impact, and each requested change is consistent with applicable federal and state laws and regulations.

Verification: The project owner shall submit to the CPM a list of ERCs to be surrendered to the District at least 60 days prior to initial startup. If the CPM, in consultation with the District, approves a substitution or modification, the CPM shall file a statement of the approval with the commission docket and mail a copy of the statement to every person on the post-certification mailing list. The CPM shall maintain an updated list of approved ERCs for the project.

STAFF OPERATIONS CONDITIONS

AQ-SC7 The project owner shall submit Quarterly Operational Reports to the CPM and District that include operational and emissions information as necessary to demonstrate compliance with Conditions **AQ-SC8**, and **AQ-1** through **AQ-48**, as applicable. The Quarterly Operational Report will specifically note or highlight instances of noncompliance and the corrective measures taken to correct these incidents.

Verification: The project owner shall submit the Quarterly Operational Reports to the CPM and the District no later than 30 days following the end of each calendar quarter.

AQ-SC8 The emissions of ammonia (ammonia slip) from each gas turbine exhaust stack following the SCR controls shall not exceed 5.0 parts per million by volume on a dry basis (ppmvd) corrected to 15 percent oxygen. Compliance with this limit shall be verified through an initial source test and annual source testing thereafter.

Verification: The project owner shall submit to the District and the CPM turbine initial source test data and annual source test data demonstrating compliance with this condition as part of the Quarterly Operational Report (**AQ-SC7**).

DISTRICT DETERMINATION OF COMPLIANCE CONDITIONS

Turbine Power Train Conditions

[Two (2) individual 1628 MMBtu/hr F Class Gas Turbine Generators]

[Conditions AQ-1 through AQ-28 apply to each combustion turbine, unless otherwise specified.]

AQ-1 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each combustion turbine, manufacturer and design data. A summary of significant operation and maintenance events for each combustion turbine shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-2 This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: The project owner shall provide in the Quarterly Operational Reports (**AQ-SC7**) either a monthly laboratory analysis showing the fuel sulfur content, a monthly fuel sulfur content report from the fuel supplier(s), or the results from a custom fuel monitoring schedule approved by U.S. EPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG.

AQ-3 This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines). This equipment is also subject to the Prevention of Significant Deterioration (40 CFR 51.166) and Federal Acid Rain (Title IV) programs. Compliance with all applicable provisions of these regulations is required.

Verification: At least ninety (90) days prior to the first firing of fuel in either turbine, the project owner shall provide the District, CARB and CPM with copies of the federal PSD and Acid Rain permits.

AQ-4 Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NOx and VOC during periods of startup, shutdown and malfunction:

a. Hourly rates, computed every 15 minutes, verified by CEMS and annual compliance tests:
   i. NOx as NO2 – 19.80 lb/hr (based on 2.5 ppmvd corrected to 15% O2 and averaged over one hour)
   ii. CO – 35.20 lb/hr (based on 5.0 ppmvd (8.4 ppmvd with duct firing or when between 70 and 80 percent of full load) corrected to 15% O2 and averaged over 24 hours)
b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
   i. VOC as CH4 – 2.9 lb/hr (based on 1 ppmvd corrected to 15% O2)
   ii. SOx as SO2 – 2.7 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
   iii. PM10 – 6.0 lb/hr

Verification: The project owner shall submit the following in the Quarterly Operational Reports (**AQ-SC7**): All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); and a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip. Any maintenance to any air pollutant control system (recorded on an as-performed basis). Any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ-5 Emissions of CO and NOx from this equipment shall only exceed the limits contained in Condition **AQ-4** during startup and shutdown periods as follows:

a. Startup is defined as the period beginning with ignition and lasting until the equipment has reached operating permit limits. Cold startup is defined as a startup when the CTG has not been in operation during the preceding 48 hours. Hot startup is defined as a startup when the CTG has been in operation during the preceding 24 hours. Warm startup is defined as a startup that is not a hot or cold startup. Shutdown is defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.

b. Transient conditions shall not exceed the following durations:
   i. Cold startup – 3.7 hours
   ii. Warm startup – 2.0 hours
   iii. Hot startup – 1.2 hours
   iv. Shutdown – 0.5 hour

c. During a cold startup emissions shall not exceed the following, verified by CEMS:
   i. NOx – 376 lb
   ii. CO – 403 lb

d. During a warm startup emissions shall not exceed the following, verified by CEMS:
   i. NOx – 278 lb
   ii. CO – 253 lb

e. During a hot startup emissions shall not exceed the following, verified by CEMS:
   i. NOx – 260 lb
   ii. CO – 172 lb

f. During a shutdown emissions shall not exceed the following, verified by CEMS:
   i. NOx – 170 lb
   ii. CO – 48 lb

Verification: The project owner shall include a detailed record of each startup and shutdown event in the Quarterly Operational Reports (**AQ-SC7**). Each record shall include, but not be limited to, duration, fuel consumption, total emissions of NOx and CO, and the date and time of the beginning and end of each startup and shutdown event. Additionally, the project owner shall report the total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, hours in shutdown, and average plant operation schedule (hours per day, days per week, weeks per year).

AQ-6 Emissions from this equipment, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:

a. NOx – 5762 lb/day, verified by CEMS
b. CO – 3808 lb/day, verified by CEMS

c. VOC as CH4 – 239 lb/day, verified by compliance tests and hours of operation in mode
d. SOx as SO2 – 130 lb/day, verified by fuel sulfur content and fuel use data
e. PM10 – 288 lb/day, verified by compliance tests and hours of operation

<u>Verification:</u> The project owner shall submit in the Quarterly Operational Reports (**AQ-SC7**) the information required by **AQ-4** and a calendar day summary of emissions demonstrating compliance with these limits.

AQ-7 Emissions from this facility, including the duct burners and cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx – 191 tons/year, verified by CEMS
b. CO – 291 tons/year, verified by CEMS
c. VOC as CH4 – 24 tons/year, verified by compliance tests and hours of operation in mode
d. SOx as SO2 – 24 tons/year, verified by fuel sulfur content and fuel use data
e. PM10 – 56 tons/year, verified by compliance tests and hours of operation

<u>Verification:</u> The project owner shall submit in the Quarterly Operational Reports (**AQ-SC7**) the information required by **AQ-4** and a rolling 12 month summary of emissions demonstrating compliance with these limits.

AQ-8 Particulate emissions from this equipment shall not exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB and Commission upon request.

AQ-9 This equipment shall exhaust through a stack at a minimum height of 130 feet.

<u>Verification:</u> Prior to the first firing of natural gas in either turbine the project owner shall provide to the District and the CPM as-built drawings of the stack or other suitable proof of the minimum stack height.

AQ-10 The project owner shall not operate this equipment after the initial commissioning period without the selective catalytic NOx reduction system with valid District permit # ___ installed and fully functional.

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-11 The project owner shall provide stack sampling ports and platforms necessary to perform source tests required to verify compliance with District rules, regulations and permit conditions. The location of these ports and platforms shall be subject to District approval.

<u>Verification:</u> Prior to the first firing of natural gas in either turbine the project owner shall provide to the District and the CPM as-built drawings of the stack or other suitable documentation of the correct and complete installation of all necessary sampling ports and access platforms.

AQ-12 Emissions of NOx, CO, oxygen and ammonia slip shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using either a Continuous Emission Rate Monitoring System (CERMS) meeting the requirements of 40 CFR 75 Appendix A or a stack flow rate calculation method. The project owner shall install, calibrate, maintain, and operate these monitoring systems according to a District-approved monitoring plan and MDAQMD Rule 218, and they shall be installed prior to initial equipment startup.

Verification: Six (6) months prior to monitoring system installation, the project owner shall submit a monitoring plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the CEMS, continuous fuel monitoring system, and CERMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-13 The project owner shall conduct all required compliance/certification tests in accordance with a District-approved test plan.

Verification: Thirty (30) days prior to the compliance/certification tests the project owner shall provide a written test plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the test plan within 15 days of its receipt. Written notice of the compliance/certification test shall be provided to the District and CPM ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-14 The project owner shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The following compliance tests are required:

a. NOx as NO2 in ppmvd at 15% O2 and lb/hr (measured per USEPA Reference Methods 19 and 20).
b. VOC as CH4 in ppmvd at 15% O2 and lb/hr (measured per USEPA Reference Methods 25A and 18).
c. SOx as SO2 in ppmvd at 15% O2 and lb/hr.
d. CO in ppmvd at 15% O2 and lb/hr (measured per USEPA Reference Method 10).
e. PM10 in mg/m3 at 15% O2 and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
f. Flue gas flow rate in dSCFM.
g. Opacity (measured per USEPA reference Method 9).
h. Ammonia slip in ppmvd at 15% O2.

Verification: The annual source test report shall be submitted to the District and CPM no later than six (6) weeks prior to the expiration date of the District permit.

AQ-15 The project owner shall, at least as often as once every five years (commencing with the initial compliance test), include the following supplemental source tests in the annual compliance testing:

a. Characterization of cold startup VOC emissions;

b. Characterization of warm startup VOC emissions;

c. Characterization of hot startup VOC emissions; and

d. Characterization of shutdown VOC emissions.

<u>**Verification:**</u> Each annual source test report (**AQ-14**) shall either include the results of these tests for the current year or document the date and results of the last such tests.

AQ-16 Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B (or otherwise District approved):

a. For NOx, Performance Specification 2.

b. For O2, Performance Specification 3.

c. For CO, Performance Specification 4.

d. For stack gas flow rate, Performance Specification 6 (if CERMS is installed).

e. For ammonia, a District approved procedure that is to be submitted by the project owner.

f. For stack gas flow rate (without CERMS), a District approved procedure that is to be submitted by the project owner.

<u>**Verification:**</u> The project owner shall provide the CPM documentation of the District's approval of the continuous monitoring systems, within 15 days of its receipt. The project owner shall make the site available for inspection of the continuous monitoring systems by representatives of the District, CARB and the Commission.

AQ-17 The project owner shall submit to the APCO and USEPA Region IX the following information for the preceding calendar quarter by January 30, April 30, July 30 and October 30 of each year this permit is in effect. Each January 30 submittal shall include a summary of the reported information for the previous year. This information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request:

a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip.

b. Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.

c. Date and time of the beginning and end of each startup and shutdown period.

d. Average plant operation schedule (hours per day, days per week, weeks per year).

e. All continuous emissions data reduced and reported in accordance with the District-approved CEMS protocol.

f. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol).

g. Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG)

h. A log of all excess emissions, including the information regarding malfunctions/breakdowns required by Rule 430.

i. Any permanent changes made in the plant process or production which would affect air pollutant emissions, and indicate when changes were made.

j. Any maintenance to any air pollutant control system (recorded on an as-performed basis).

Verification: The project owner shall provide this information to the District and CPM in the Quarterly Operational Reports (**AQ-SC7**).

AQ-18 The project owner must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 191 tons of NOx, 48 tons of VOC, 48 tons of SOx, and 56 tons of PM10 offsets (NOx ERCs may be substituted for VOC ERCs at a rate of 1.0:1, and PM10 ERCs may be substituted for SOx ERCs at a rate of 1.0:1).

Verification: The project owner must submit all ERC documentation to the District and the CPM prior to the start of construction.

AQ-19 During an initial commissioning period of no more than 180 days, commencing with the first firing of fuel in this equipment, NOx, CO, VOC and ammonia concentration limits shall not apply. The project owner shall minimize emission of NOx, CO, VOC and ammonia to the maximum extent possible during the initial commissioning period.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-20 The project owner shall tune each CTG and HRSG to minimize emissions of criteria pollutants at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-21 The project owner shall install, adjust and operate each SCR system to minimize emissions of NOx from the CTG and HRSG at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor. The NOx and ammonia concentration limits shall apply coincident with the steady state operation of the SCR systems.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-22 The project owner shall submit a commissioning plan to the District and the Energy Commission at least four weeks prior to the first firing of fuel in this equipment. The commissioning plan shall describe the procedures to be followed during the commissioning of the CTGs, HRSGs and steam turbine. The commissioning plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the timing of the dry low NOx combustors, the installation and testing of the CEMS, and any activities requiring the firing of the CTGs and HRSGs without abatement by an SCR system.

Verification: At least four (4) weeks prior to the first firing of natural gas in either turbine, the project owner shall submit a detailed Initial Commissioning Plan to the District and the CPM. This plan should provide detailed technical information regarding initial commissioning in a format that facilitates technical verification.

AQ-23 The total number of firing hours of each CTG and HRSG without abatement of NOx by the SCR shall not exceed 350 hours during the initial commissioning period. Such operation without NOx abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place and operating. Upon completion of these activities, the project owner shall provide written notice to the District and Energy Commission and the unused balance of the unabated firing hours shall expire.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-24 During a period that includes a portion of the initial commissioning period, emissions from this facility shall not exceed the following emission limits (verified by CEMS):

a. CO – 421 tons/year (rolling 12 month summary), 44,000 pounds/calendar day and 2000 pounds/hour

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report. In addition, after the end of the initial commissioning period the project owner shall continue to report the above data in the Quarterly Operational Report (**AQ-SC7**) for as long as monitoring period includes a portion of the initial commissioning period.

AQ-25 During a period that includes a portion of the initial commissioning period, prior to the steady state operation of the SCR system, emissions from this facility shall not exceed the following emission limits (verified by CEMS):

b. NOx – 273 tons/year (rolling 12 month summary), 22,000 pounds/calendar day and 1000 pounds/hour

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report. In addition, after the end of the initial commissioning period the project owner shall continue to report the above data in the Quarterly Operational Report (**AQ-SC7**) for as long as monitoring period includes a portion of the initial commissioning period.

AQ-26 Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the emission limits in Condition **AQ-4**.

Verification: Thirty (30) days prior to the initial compliance test, the project owner shall provide a written test plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the test plan within 15 days of its receipt. Written notice of the initial compliance test shall be provided to the District and CPM ten (10) days prior to the tests so that an observer may be present. A written report with the results of such initial compliance tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-27 The initial compliance test shall include tests for the following. The results of the initial compliance test shall be used to prepare a supplemental health risk analysis:

a. Formaldehyde;
b. Certification of CEMS and CERMS (or stack gas flow calculation method) at 100% load, startup modes and shutdown mode;
c. Characterization of cold startup VOC emissions;
d. Characterization of warm startup VOC emissions;
e. Characterization of hot startup VOC emissions; and
f. Characterization of shutdown VOC emissions.

Verification: The results of the initial compliance test (see **AQ-26**) and a supplemental health risk analysis shall be submitted to the District and the CPM within forty-five (45) days after testing.

AQ-28 The project owner shall provide sufficient space and appurtenances within the Heat Recovery Steam Generator to allow the subsequent installation of a high temperature oxidation catalyst, should one be required by the District after construction.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each HRSG, manufacturer and design data showing this feature. If any VOC or CO limit specified by the above conditions is violated, within six (6) weeks the project owner shall submit a plan to install an oxidation catalyst. The catalyst shall be installed and operational within six (6) months of the violation.

Duct Burner Conditions

[Two (2) individual 132 MMBtu/hr Natural Gas Duct Burners]

AQ-29 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each duct burner system, manufacturer and design data. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-30 This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, and Commission. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-31 The duct burner shall not be operated unless the combustion turbine generator with valid District permit # ___ and selective catalytic NOx reduction system with valid District permit # ___ are in operation.

Verification: A summary of fuel use and equipment operation for each duct burner shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-32 Fuel use by this equipment shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: The above information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District or Commission personnel upon request.

Selective Catalytic NOx Reduction System Conditions

[Two (2) individual SCR systems]

AQ-33 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each selective catalytic reduction system, manufacturer and design data. A summary of significant operation and maintenance events for each selective catalytic reduction system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-34 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each selective catalytic reduction system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-35 This equipment shall be operated concurrently with the combustion turbine generator with valid MDAQMD permit # ___.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and Commission upon request.

AQ-36 Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded 550° Fahrenheit except for periods of equipment malfunction. Except during periods of startup, shutdown and malfunction, ammonia slip shall not exceed 10 ppmvd (corrected to 15% O2), averaged over three hours.

Verification: The project owner shall maintain a log of the SCR temperatures and the commencement of ammonia injection times. This information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Commission personnel upon request.

AQ-37 Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to MDAQMD personnel on request.

Verification: The above information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Commission personnel upon request.

Cooling Tower Conditions

[One Cooling Tower]

AQ-38 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each cooling tower, manufacturer and design data. A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-39 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-40 The drift rate shall not exceed 0.0006 percent with a maximum circulation rate of 146,000 gallons per minute (gpm). The maximum hourly PM10 emission rate shall not exceed 0.67 pounds per hour from both cooling towers, as calculated per the written District-approved protocol.

Verification: Compliance documentation in accordance with the written District approved protocol shall be submitted to the District and the CPM.

AQ-41 The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: A summary of the results of the weekly blow-down water quality tests and the results of the mass emission rate calculations shall be submitted in the Quarterly Operational Reports (**AQ-SC7**).

AQ-42 The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

Verification: Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District and CPM review.

AQ-43 A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and available to District personnel on request.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

Emergency Fire Pump Conditions

[One emergency IC engine driving a fire pump]

AQ-44 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of the fire pump engine, manufacturer and design data. A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-45 This equipment shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.

Verification: A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-46 This unit shall be limited to use for emergency fire fighting, and as part of a testing program that does not exceed 60 minutes of testing operation per week (up to two hours once per year for annual testing and up to four hours once every three years for triennial testing).

Verification: The project owner shall make the fire pump engine operating records available for inspection by representatives of the District, CARB and the Commission upon request. The information shall be maintained on-site for a minimum of five years and shall be provided to District and/or Commission personnel on request.

AQ-47 The project owner shall use only diesel fuel whose sulfur concentration is less than or equal to 0.05% on a weight per weight basis in this unit.

Verification: The project owner shall make fuel purchase, MSDS or other fuel supplier records containing diesel fuel sulfur content available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-48 The project owner shall maintain a log for this unit, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of five (5) years and shall be provided to District personnel on request:

a. Date of each use or test;
b. Duration of each test in minutes;
c. Fuel consumed during each calendar year, in gallons; and,
d. Fuel sulfur concentration (the project owner may use the supplier's certification of sulfur content if it is maintained as part of this log).

Verification: The project owner shall make the fire pump engine operating records available for inspection by representatives of the District, CARB and the Commission upon request.

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BIOLOGICAL RESOURCES

Natasha Nelson

INTRODUCTION

This section provides the California Energy Commission (Energy Commission) staff's analysis of potential impacts to biological resources from Caithness Blythe II, LLC's (applicant's) proposal for the construction and operation of the Blythe Energy Project II (BEP II). This analysis is primarily directed toward impacts to state and federally listed species, species of special concern, riparian vegetation, and other areas of critical biological concern. This document presents information regarding the affected biotic community, the potential environmental impacts associated with the construction and operation of the proposed project, and where necessary, specifies mitigation planning and compensation measures to reduce potential impacts to non-significant levels. This document also determines compliance with applicable laws, ordinances, regulations and standards (LORS), and specifies conditions of certification.

This analysis is based, in part, on information provided in the Applicant's Application For Certification (AFC) as revised on July 3, 2002 (BEP II 2002a, BEP II 2002d), Applicant's responses to Data Requests submitted on September 30, 2002 and March 14, 2003 (BEP II 2002g, BEP II 2003b) site visit and discussion with Western Area Power Administration (WAPA), California Department of Fish and Game and U.S. Fish and Wildlife Service (USFWS), and correspondence between WAPA the USFWS. This site has been the subject of a previous Energy Commission amendment (CEC 2002), information from which was also used in preparing this analysis.

LAWS, ORDINANCES, REGULATION AND STANDARDS

The applicant will need to abide by the following laws, ordinances, regulations, and standards (LORS) during project construction and operation.

FEDERAL

Endangered Species Act of 1973

Title 16, United States Code, section 1531 et seq., and Title 50, Code of Federal Regulations, part 17.1 et seq., designate and provide for protection of threatened and endangered plant and animal species, and their critical habitat.

Migratory Bird Treaty Act

Title 16, United States Code, sections 703-712, prohibits the take of migratory birds.

STATE

California Endangered Species Act of 1984

Fish and Game Code sections 2050 et seq. protects California's rare, threatened, and endangered species.

Nest or Eggs-Take, Possess, or Destroy

Fish and Game Code section 3503 protects California's birds by making it unlawful to take, possess, or needlessly destroy the nest or eggs of any bird.

Birds of Prey or Eggs-Take, Possess, or Destroy

Fish and Game Code section 3503.5 protects California's birds of prey and their eggs by making it unlawful to take, possess, or destroy any birds of prey or to take, possess, or destroy the nest or eggs of any such bird.

Migratory Birds-Take or Possession

Fish and Game Code section 3513 protects California's migratory birds by making it unlawful to take or possess any migratory non-game bird as designated in the Migratory Bird Treaty Act or any part of such migratory non-game bird.

Fully Protected Species

Fish and Game Code sections 3511, 4700, 5050, 5515 prohibit take of animals that are classified as Fully Protected in California.

Significant Natural Areas

Fish and Game Code section 1930 et seq. designates certain areas such as refuges, natural sloughs, riparian areas and vernal pools as significant wildlife habitat.

Native Plant Protection Act of 1977

Fish and Game Code section 1900 et seq. designates state rare, threatened, and endangered plants.

California Code of Regulations

Title 14, sections 670.2 and 670.5 list animals of California designated as threatened or endangered.

LOCAL

Riverside County, California General Plan; Environmental Hazards and Resources

Goal 6 is to recognize and protect rare, threatened and endangered species of wildlife and vegetation as important County resources and a source of natural diversity.

Goal 8 is to recognize and promote the conservation of unique species of wildlife and vegetation found within a locale as an important County resource.

Riverside County, Airport Land Use Plan

The Comprehensive Land Use Plan for Blythe Airport, Riverside County, California (CLUP) was adopted by the Riverside County Airport Land Use Commission (ALUC) in August 1992. The CLUP is intended to protect and promote the safety and welfare of residents in the airport vicinity and users of the airport while ensuring continued operation of the airport. Five safety zones are defined around airports to promote the safety of persons on the ground while reducing risks of serious harm to crews and passengers of aircraft making forced landings in the immediate environs of the airport, and BEP II is within four of the five safety zones (see LAND USE section of this PSA). The CLUP states that any gathering of birds shall be prohibited within all safety zones. The County's General Plan allows for land use constraints (including restricting bird attractants in the flight zone) to protect surrounding residents.

City of Blythe, California General Plan

Biological Resources Goal 1 is to preserve and protect the City and regional biological resources, especially those of sensitive, rare, threatened, or endangered species of wildlife and their habitat and to encourage a balance between nature and human development.

Biological Resources Policy 1 is that the City will coordinate and cooperate with State and Federal agencies to preserve and enhance the recreational opportunities for fishermen and conserve habitat in the Colorado River.

Biological Resources Policy 2 is that the City will require or insist that responsible County, State and Federal agencies assure the provision of ample natural and enhanced open-space setbacks from the Colorado River's edge in conjunction with any development near or adjacent to the river's edge.

Biological Resources Policy 4 is that the Palo Verde Mesa habitat area extending from Interstate 10 to 20th Avenue and desert land immediately west will be designated as Open Space on the General Plan land use map to assure their protection as valuable and important wildlife habitat.

Biological Resources Policy 8 is that the City will encourage and/or if appropriate, require the use of native trees and vegetation, including palo verde, mesquite, cottonwood, ocotillo, and screwbean, in public areas, private common areas, street dividers, and other landscape areas where Planning Division control can be exercised.

Open Space and Conservation Goal 5 is the preservation of riparian and ruderal habitats as important breeding and foraging habitat for native and migratory birds and animals.

SETTING

REGIONAL

The proposed power plant is located in eastern Riverside County, just west of the Colorado River flood plain. The Palo Verde Valley was seasonally inundated by the Colorado River before several large dams were constructed upstream of Blythe. Since the installation of the dams and subsequent irrigation canals and drains, the Palo Verde Valley, and the surrounding terraces, have been transformed into a large agricultural area and service communities like Blythe have continued to grow. The remnant plant communities outside the agricultural and residential areas include: creosote bush (*Larra tridentata*) scrub, disturbed desert areas, and riparian plant communities along the Colorado River and various canals and drains.

A variety of sensitive species are found in the project region. Sensitive species known to occur in the project region include desert tortoise (*Gopherus agassizii*), mountain plover (*Charadrius montanus*), southwestern willow flycatcher (*Empidonax traillii extimus*), Yuma clapper rail (*Rallus longirostris yumanensis*), and razorback sucker (*Xyrauchen texanus*). Desert tortoises are found primarily on flats with scattered shrubs and abundant herbaceous plants, with soils ranging from sand to sandy-gravel.

Mountain plover forage from September to March within agricultural fields which have been recently cleared or burned, but do not nest in California. The remainder of the species are concentrated along the banks of the Colorado River which supports wetland and riparian communities. BIOLOGICAL RESOURCES Table 1 includes the list of the sensitive species that staff considered for this proposed project.

The BLM Desert Plan (BLM 1980) as amended established three desert tortoise management Categories (I, II, III) for public land in the California desert. These categories supercede the original crucial habitat designations in the Desert Plan. The goals for the Categories are as follows:

- Category I habitat is to maintain stable, viable populations, and to protect existing tortoise habitat values
- Category II is to maintain stable, viable populations and halt further declines in tortoise habitat values
- Category III is to limit tortoise habitat declines to the extent possible by mitigating impacts.

Although the project site does not fall within one of these Categories, there are Category I lands (designated as the Chuckwalla Desert Wildlife Management Area) approximately 6 miles west and Category III lands approximately 6 miles north.

LOCAL

East of the property is a 520-MW power plant and the Buck Boulevard substation which became operational in the summer of 2003. Beyond the developing power plant facility is a large citrus grove, which is in operation under Sun World, and the Western Area Power Administration's Blythe Substation. To the west is a sewage treatment facility and beyond that is the Blythe Airport which is a municipal facility providing regional air services with a daily maximum of 50 takeoffs or landings. Hobsonway runs along the southern border of the project, and just south of that is Interstate 10. Hobsonway serves as an Interstate10 frontage road and a city business loop. This section of Interstate 10 connects Los Angeles to Phoenix or Tucson, and is highly traveled by trucks carrying cargo. Properties to the north contain agricultural lands and abandoned citrus groves that have now revegetated themselves with locally abundant species.

Power Plant Site

No sensitive species were identified on the site prior to the placement of fill (see Staff Analysis for the Blythe Amendment, CEC 2002). No species are expected within the fenceline so long as it is maintained and gates are kept closed, but occasionally species may gain access to the site. For instance, a single kit fox (*Vulpes macrotis*) was found trapped within the fence during the pre-construction survey for disposal of fill on the site despite the fence being complete (Blythe Energy Project 2003); birds can also access the site.

BIOLOGICAL RESOURCES - Table 1
Sensitive Species
(BEP II 2002a, Tables 7.12-1 and 7.12-2)

Sensitive Plants	Status*
Harwood's milkvetch (*Astragalus insularis var. harwoodii*)	CNPS List 2
Sensitive Wildlife	**Status***
California leaf-nosed bat (*Macrotus californicus*)	FSC/CSC
Cave myotis (*Myotis velifer*)	FSC/CSC
Occult little brown bat (*Myotis lucifugus occultus*)	FSC/CSC
Yuma myotis (*Myotis yumanensis*)	FSC/CSC
Greater western mastiff bat (*Eumops perotis californicus*)	FSC/CSC
Pale Townsend's big-eared bat (*Plecotus townsendii pallescens)*	FSC/CSC
Pallid bat (*Antrozous pallidus*)	CSC
Spotted bat (*Euderma maculatum*)	FSC/CSC
Brown pelican (*Pelecanus occidentalis*)	FE/CE
Western least bittern (*Ixobrychus exilis hesperis*)	FSC/CSC
White-faced ibis (*Plegadis chihi*)	FSC/CSC
Yuma clapper rail (*Rallus longirostris yumanensis*)	FE/CT
California black rail (*Laterallus jamaicensis coturniculus*)	FSC/CT/CFP
Western snowy plover (*Charadrius alexandrinus nivosus*)	FT/CSC
Mountain plover (*Charadrius montanus*)	CSC
Golden eagle (*Aquila chrysaetos*)	CSC/CFP
Bald eagle (*Haliaeetus leucocephalus*)	FPD/CE
Ferruginous hawk (*Buteo regalis*)	FSC/CSC
Merlin (*Falco columbarius*)	CSC
Prairie falcon (*Falco mexicanus*)	CSC
American peregrine falcon (*Falco peregrinus anatum*)	CE
Western yellow-billed cuckoo (*Coccyzus americanus occidentalis*)	CE
Short-eared owl (*Asio flammeus*)	CSC
Western burrowing owl (*Athene cunicularia hypugaea*)	FSC/CSC/CP
California horned lark (*Eremophila alpestris actia*)	CSC
Gila woodpecker (*Melanerpes uropygialis*)	CE
Gilded northern flicker (*Colaptes chrysoides*)	CE
Vermilion flycatcher (nesting) (*Pyrocephalus rubinus*)	CSC
Southwestern willow flycatcher (*Empidonax traillii extimus*)	FE/ST
Loggerhead shrike (*Lanius ludovicianus*)	FSC/CSC
Crissal thrasher (*Toxostoma crissale*)	CSC
LeConte's thrasher (*Toxostoma lecontei*)	CSC
Bell's vireo (*Vireo bellii arizonae*)	FE/CE
Sonoran yellow warbler (*Dendroica petechia sonorana*)	CSC
Yellow-breated chat (*Icteria virens*)	CSC
Northern cardinal (*Cardinalis cardinalis*)	CSC
Large-billed savannah sparrow (*Passerculus sandwichensis rostatus*)	FSC/CSC
Summer tanager (*Piranga rubra*)	CSC
Desert tortoise (*Gopherus agassizii*)	FT/ST
Flat-tailed horned lizard (*Phrynosoma macallii*)	CSC

* STATUS – FE = Federally listed Endangered; FT = Federally listed Threatened; FSC = Federal Species of Special Concern; FPE = Federal Proposed Endangered; FPD = Federal proposed (Delisting); CNPS List 2 = Plants rare, threatened or endangered in California but more common elsewhere; CE = California listed Endangered, CT = California listed Threatened; CSC = California Species of Special Concern; CP= California Proposed for Listing; CFP: California Fully-protected Species

Prior to the placement of fill on the site starting in May 2003, the vegetation community for the proposed power plant site and construction laydown area was Sonoran creosote bush, dominated by creosote and white bursage (*Ambrosia dumosa*) on sandy and gravelly soils. The site had some off-road tracks on it and some illegal dump sites were present. Sonoran creosote bush scrub is habitat for desert tortoise, a federal and state-listed species. Because the area had been categorized as potential desert tortoise and Harwood milkvetch (*Astragalus insularis var. harwoodii*) habitat, it was mitigated for under the Blythe Amendment Biological Opinion (USFWS 2002a) and the Commission Order on the amendment (CEC 2002). No vegetation remains on site, but staff expects vegetation for erosion control to be planted at the end of the soil disposal operation. Ground nesting birds, such as burrowing owls, could return to the site at any time after final grading.

The cultural resource site on the northern end of the parcel has been fenced in a manner that will allow passage of desert tortoises, or other wildlife to use the area until such time as the site is classified as to its importance. Under the Blythe Amendment, the habitat loss of this area was mitigated because the applicant wanted to reserve the right to develop the area in the future without any additional permit review. The cultural resource site is covered with Sonoran creosote bush scrub.

The project would have one evaporation pond, divided into two cells with a nominal surface area of 6.48 acres and a storage capacity of approximately 26 acre-feet (BEP II 2002g, Data Response 59). The cells are approximately 15 feet deep with 13 feet of water and solid storage (BEP II 2002g, Data Response 59). The pond would be lined with a black plastic liner and water would be allowed to evaporate unassisted. The primary water stream to the evaporation pond would be from the water treatment plant. The maximum flow rate of the treatment plant would be 13 gallons per minute (BEP II 2002a, Figure 7.13-10B; BEP II 2002a Section 2.2.10.1.1). Concentrated brine from the cooling tower is also directed to the evaporation ponds at a rate of 1 to 20 gallons per minute depending on ambient temperature (BEP II 2002a, Figures 7.13-10A and 7.13-10B). The wastewater from the brine concentrator would have a sodium concentration of over 58,000 milligrams per liter (mg/L; BEP II 2002d, Table 7.13-7), which is nearly 1.5 times the salinity of ocean water. The wastewater would also have a high selenium concentration (1.8 mg/L; BEP II 2002a, Table 7.13-7). The site would direct surface runoff from rain events to the stormwater retention basin designed for the Blythe Energy Project (BEP II 2002g, Data Response 69).

Traffic to and from the site is mostly along Hobsonway and Interstate 10. These roads cross through urban development, agriculture, and some disturbed native scrub habitat. A worker living in Blythe would cross several canals to reach work, including Goodman drain. To enter the site, workers would go north on Buck Boulevard between Blythe Energy Project and the citrus grove, and then travel west on Riverside Avenue. The area north of Riverside Avenue is undeveloped and is covered in Sonoran creosote bush scrub.

The City of Blythe upgraded Riverside Avenue to a 40 foot width within the 60 foot right-of-way. This work included drainage swales to divert the overland flows from the north to a drainage system at Buck Boulevard. The northwest corner of Riverside and Buck Avenues has some disturbance and soil compaction as it was used for waste storage during construction of the Blythe Energy Project and Buck Boulevard Substation (N.Nelson, personal observation).

Worker parking and staging would take place on a 10 acre portion of the power plant site. Workers are to access the site from the northern gate off of Riverside Avenue. The driveway from the north has desert-tortoise proof fencing on both the west and east side and the gate has also been built to be desert-tortoise proof.

Linear Facilities

All linear facilities that would serve the proposed power plant, such as the natural gas pipeline, were built during the construction of the adjacent 520-MW power plant. All linears are within the fenceline of the proposed facility with the exception of the transmission line which would need to cross the adjacent power plant facility to reach the Buck Boulevard switchyard. The Buck Boulevard switchyard was constructed on the adjacent 76-acre parcel, and is fully enclosed with a desert tortoise proof fence. An 800-foot transmission line would be constructed from BEP II to the switchyard, and the switchyard would be expanded within the current fenceline. The entire 76-acre eastern parcel is industrial.

IMPACTS AND ANALYSIS

STAFF'S CRITERIA FOR DETERMINING IMPACT SIGNIFICANCE

The California Environmental Quality Act (CEQA) Guidelines define direct impacts as those impacts that result from the project and occur at the same time and place. Indirect impacts are caused by the project, but can occur later in time or farther removed in distance, but are still reasonably foreseeable and related to the project. The potential impacts discussed below are those most likely to be associated with construction and operation of the project. As a result of the project, the applicant may volunteer to place up to 786 acres of irrigated lands in rotational fallowing or permanent retirement. The implications of this fallowing were also reviewed by staff for potential impacts.

CEQA guidelines provide an environmental checklist to assist lead agencies in their analysis of project impacts. The headings for discussion of impacts presented in this section follow the items in that checklist, as well as items found in the Warren-Alquist Act and recent Presidential (executive) orders relevant to biological resources (e.g., Executive Order 13112 for management of invasive species). Significance is generally determined by compliance with applicable LORS; however, because of the diversity of biological impacts, guidelines adopted by resource agencies may also be used. These are appropriately cited in the text.

IMPACTS TO SENSITIVE SPECIES AND COMMUNITIES

The power plant site is located on a high disturbed, fenced parcel, adjacent to a power plant (which began operation in June 2003), intensive agriculture, a major interstate, and an airport. Although remnants of native plant and wildlife communities are in the regional area, the direct impacts from the construction of the project are quite limited. To ensure the remaining biological resources are protected the project owner has proposed to retain a Designated Biologist (Conditions of Certification **BIO-1** to **BIO-3**) and to have a worker education program (Condition of Certification **BIO-4**). All mitigation will be compiled into a comprehensive document known as a Biological Resources Mitigation and Monitoring Plan (BRMIMP, Condition of Certification **BIO-5**).

Power Plant Site

Because the entire 76-acre power plant site has been fenced to exclude wildlife, construction of the project would not permanently remove the open space area from use by transient wildlife. The loss of this open space took place when the area was fenced for the adjacent power plant's excess fill disposal and the loss was already compensated for under the Blythe Energy Project expansion (USFWS 2002a; see Staff Analysis of the Blythe Energy Project Amendment, CEC 2002). However, the site will be managed to reduce potential harm and the fence will be monitored to ensure its integrity during construction (Conditions of Certification **BIO-6** to **BIO-8**).

Workers and delivery vehicles would access the site from Riverside Avenue. While Buck Boulevard and Hobsonway have urban uses along their shoulders, Riverside Avenue is open to potential desert tortoise habitat to the north and has very little local traffic. A peak working day will generate 640 to 690 project-related trips on these roads (BEP II 2002a, Table 7.4-6). While unpaved roads that carry only 25 cars per day show no impacts to desert tortoises, roads that carry average daily traffic of 220 to 800 vehicles can cause declines in desert tortoise sign out to 1.4 miles (2.25 km) from the road (Hoff and Marlow 2002). The high number of vehicles along Interstate 10 and Hobsonway has probably already depressed desert tortoise populations out to 2.6 miles (4.25 km), and increased construction traffic would not add to this existing impact. However, traffic-related fatalities as vehicles exit the site and continue along Riverside Avenue can be reduced with worker education and appropriate speed limits (Condition of Certification **BIO-4**).

Burrowing owls were found during monitoring of the natural gas line installed for Blythe Energy Project and this species could move onto the site at any time (BEP II 2002a, Section 7.12.2.3). Nesting activity will also be assessed by pre-construction surveys within 30 days of project construction and avoidance measures would then be taken to reduce impacts to less than significant levels (Conditions of Certification **BIO-12**). The Fish and Game Commission received a petition to list the western burrowing owl as an endangered or threatened species on April 3, 2003 (Fish and Game Commission 2003). A ruling on the petition was scheduled for October 2, 2003, but has been delayed while the Fish and Game Commission evaluates public comment. Because of the expected vote on candidacy of this species, staff will treat this species as if it already was a state-listed species, and require the applicant apply for "take" of the species in the event they are found on-site or in the buffer around the site. To approve "take" of a state listed species, the applicant must show that full mitigation of impacts has been achieved. This means more mitigation will be required than is currently proposed by the applicant, or than was proposed by staff in previous analyses. To conclusively prove that owls are not present on the site, and thus to avoid consultation, the applicant must complete a total of four site visits from two hours before sunset to one hour after or from one hour before to two hours after sunrise during nesting season (April 15 to July 15). If no owls are found during the nesting season surveys then a winter survey (from December 1 to

January 31) is necessary to determine absence. Negative results during surveys outside of the above periods are not conclusive proof that owls do not use the site. Prior to staff's issuance of the Final Staff Assessment, the applicant must make a choice of assuming presence and undergoing 2081(b) consultation, performing the proper surveys, or accepting a condition of certification which may delay construction until the proper breeding and winter surveys can be completed to show absence.

Construction at night would require local area lighting and noise at a time that is typically dark and quiet. It could also increase risk to species that are nocturnal, such as bats, when they enter the active construction zone. Worker's should be educated about the use of the site by wildlife in both daytime and nighttime scenarios (Condition of Certification **BIO-4**) and lighting shall be shielded to reduce its impact off-site (Condition of Certification **BIO-6**).

During operations, the cooling towers will emit mist and droplets of water into the atmosphere (known as cooling tower drift). Heavier droplets can fall onto soil and vegetation, and once evaporated, leave behind minerals and salts. Cooling water is cycled several times, and chemicals are added to reduce scaling of pipes and other equipment, thus, any droplet is likely to have salt and chemical components. The applicant estimates that the annual predicted deposition of cooling tower drift (in the form of PM10) would be 0.86 grams per square meter using conservative assumptions in the analysis (BEP II 2002a, page 7.12-8). Studies by Pawha and Shilpey (1979) are often used as a threshold for significant impacts from cooling tower mist. The study exposed salt-sensitive vegetation (corn, tobacco, and soybeans) to saltwater mist and determined an annual rate of 2.98 grams per square meter was required to induce salt stress symptoms. Because the projects emissions are less than one-third of the threshold, the operation of the proposed cooling towers is not expected to cause harm to surrounding vegetation.

The proposed evaporation ponds could attract bird and other wildlife (e.g. waterbirds, bats, etc.). The water directed to the evaporation ponds would contain some level of contaminants, including selenium, and would be extremely saline (>58,000 mg/L, BEP II 2002d, Table 7.13-7). The direct loss of birds, bats, and/or other wildlife could result from ingesting these contaminants. Many of these species are protected under the Migratory Bird Treaty Act and other state and federal laws. Waterborne selenium is not is not very toxic if it is the only exposure route, but levels above 2.2 mg/L appear to impact mallard immune systems (Skorupa 1998). Invertebrates, if uncontrolled, can populate a pond and accumulate levels of selenium over 3 parts per million in just 3 years (SEGS VIII and IX, Semi-Annual Water Quality Reporting submitted to the Energy Commission). Selenium concentrations in wastewater over 0.005 mg/L in combination with invertebrates with concentrations greater than 3 parts per million (dry weight) are considered hazardous to the health and long-term survival of wildlife populations (Lemly 1997). Applicant's have proposed chemical treatments to exterminate invertebrates in attempts to prevent the bioaccumulation of selenium (or other toxins) in birds (e.g., at SEGS VIII and IX evaporation ponds).

Salt toxicosis in waterfowl has been reported in ponds with sodium concentration over 17,000 milligrams per liter (USFWS 1992, Windingstad et al. 1987). Birds spending a minimum of three hours on evaporation ponds with 52,000 to 66,000 mg/L sodium concentrations were considered to have toxic brain sodium concentrations (USFWS 1992). Salt toxicosis occurs when the bird can no longer excrete salt at levels equal to ingestion, and can be reversed if the birds can obtain fresh water. Salt toxicosis is more likely in birds that do not have previous exposure to saline waters, and thus have small supra-orbital salt glands, or birds that are under some form of stress (Wobeser and Howard 1987). Another risk is that sodium can crystallize and encrust wildlife so that they can no longer fly when water temperatures fall near freezing (Wobeser and Howard 1987).

Due to evaporation, the concentration of selenium and salt would increase in suspension and at the bottom of the proposed evaporation ponds over time. Thus, birds spending even less than three hours could ingest a lethal dose of sodium and can be exposed to levels of selenium that depress their immune systems. Staff has proposed bird hazing to prevent harm from selenium and salt toxicosis (Conditions of Certification **BIO-10** and **BIO-11**). Bird hazing systems can reduce average mortality rates from 84 per year to 20 per year on 300 acre ponds (BLM 2002). However, eliminating evaporation ponds would eliminate any possible bird losses and staff would request the applicant consider converting to another brine disposal method. For instance, Appendix A of the PSA suggests that a zero liquid discharge to brine cakes would eliminate the need for evaporation ponds.

Another concern regarding the evaporation ponds is the potentially undesirable result of attracting birds to the power plant site which is close to the Blythe airport. To address potential concerns, staff has recommended bird hazing be installed or the applicant eliminate evaporation ponds from their project design.

The cultural resource area on the north edge of the parcel is currently fenced, but does not limit access to desert tortoises and other wildlife. If however there is no cultural significance to the area, the area may become developed. Because the cultural area could become occupied with desert tortoises at any time, the project must survey for sensitive species prior to any disturbance of the land (see Conditions of Certification **BIO-12** and **BIO-13**).

There are no impacts associated with the worker parking and staging area because it will be located on previously disturbed land that has been fenced to exclude desert tortoises. But construction traffic to and from this area is a concern (see discussion above).

Linear Facilities

Electrical lines would need to be installed, however they cross an already industrialized site, so there is not a direct loss to species. Lines would be built following Avian Power Line Interaction Committee Guidelines (BEP II 2002a, BEPII Condition of Certification BIO-1) so the potential for electrocution of large perching birds and avian species collision is low. The additional transmission lines being proposed by IID from Blythe to Palm Springs are discussed under cumulative impacts.

Critical Habitat and Recovery Plan Goals

The nearest critical habitat unit for the desert tortoise is the Chuckwalla Bench located approximately 10 miles to the west. This unit was established in 1994 as part of the USFWS management to protect this species. The same area is to be managed per the prescriptions of the 1994 Desert Tortoise (Mojave Population) Recovery Plan (USFWS 1994). Declines in the population at Chuckwalla bench have been severe, attributable to vandalism, vehicle kills, raven predation and shell disease (USFWS 1994). The proposed power plant would not increase the risk of any of these threats and would not have any physical effects on this area.

The lower Colorado River is one of six Recovery Units defined within the Recovery Plan for the southwestern willow flycatcher. The goal for flycatcher populations in this segment of the Colorado River is to increase territories from the existing 3 to 150. The lower Colorado River is a managed river with three large dams (Hoover, Davis and Parker) and five small dams (Headgate Rock, Palo Verde, Imperial, Laguna and Morelos) that provide diversions for agricultural and municipal uses serving three states and the Republic of Mexico. Virtually all the riverine reaches remaining after the construction of the large and small dams were channelized or stabilized to some degree. These flood management structures have had an irreversible impact on the amount of riparian vegetation within the river. Many solutions for improving flycatcher habitat require increased availability of water in active channels or in near-channel areas. The project's use of groundwater (even when considered in conjunction with the adjacent power plant's water use) is unlikely to measurably decrease water availability in the Colorado River or in near-channel areas, and there is little possibility of impacts to southwestern willow flycatcher Recovery Plan goals. However, the Recovery Plan states: "All water users, whether municipal, agricultural, or industrial, need to work together and bear their share of water overdraft problems to achieve results" (USFWS 2002b, p. 110). WATER RESOURCES staff is proposing several ways to decrease the amount of groundwater used (see Appendix A to this PSA). All actions to reduce the use of groundwater (or fresh water) would be consistent with the southwestern willow flycatcher Recovery Plan goals.

Agricultural Fallowing or Permanent Retirement

If the regulatory environment changes, the applicant has volunteered that up to 786 acres of irrigated lands would be placed into rotational fallowing or permanent retirement. Fields would be left as stubble or as clodded earth for up to five years, and orchards may be removed (BEP II 2002d, Section 7.13.3, pp. 7.13-25 to 7.13-27). The use of agricultural land by sensitive wildlife, whether active or fallow, is limited due to the highly developed nature of the Palo Verde Valley plateau and high human presence. No special status species are identified as residing on agricultural lands exclusively, however wintering mountain plover are attracted to recently disturbed fields and sparse vegetation. Use of fallowed fields by the plover could increase with the lower level of human activity on the sites or decrease due to the loss of prey (grasshoppers). Overall, removing 786 acres of fields out of random and sporadic cycle of disturbance (from fire or tilling) would be small in comparison to the number of fields still in the vicinity (estimated at 104,000 irrigated acres). In addition, the sparse vegetation on the fallowed fields could be as attractive to the plover as a recently burned field, if prey items were available. Staff does not expect impacts to special status species as a result of fallowing or permanent retirement of fields, if it becomes necessary.

IMPACTS TO SURFACE WATERS

Runoff from the project site would be contained in a stormwater detention pond. Wastewater from the site would be stored in lined evaporation ponds. No surface waters are expected to be contaminated so long as the Waste Discharge Permit conditions are followed (see WATER RESOURCES).

IMPACTS TO MIGRATION CORRIDORS

The nearest potential wildlife corridor is the Colorado River which attracts a large number of species because of its abundant year-around water and diverse vegetation. Project construction and operation are of sufficient distance from the river, that no impact is expected.

IMPACTS TO COMMERCIAL AND RECREATIONAL SPECIES

BEP II is located in a low biological diversity area. No commercial or recreational species were identified during surveys at the site or within 1 mile of the site.

IMPACTS FROM WEEDS

The permanent and temporary earth disturbance adjacent to native habitats increases the potential for exotic, invasive plant and animal species to establish and disperse into native plant communities, which leads to community and habitat degradation. Both the State and Federal governments have recognized and taken action on the threat that exotic species pose to native habitats and agriculture. As exotic plants replace native habitat, many species of birds, insects, fish and other wildlife may be lost. It has been estimated that invasive pest plants cost California hundreds of millions of dollars annually (CalEPPC 1999). California's Governor Davis signed and funded Assembly Bill 1168 - Noxious Weeds Management Program in 1999, indicating the State's commitment to manage noxious weeds. At the federal level, Executive Order 13112 was also signed in 1999, to "prevent the introduction of invasive species and provide for their control and to minimize the economic, ecological, and human health impacts that invasive species cause". Staff seeks to prevent indirect impacts to native plant communities on the north and west side of the power plant site and has weed control as part of the project owner’s responsibility (see Condition of Certification **BIO-7**).

CUMULATIVE IMPACTS

Cumulative impacts are those that result from the incremental impacts of an action added to other past, present, and reasonably foreseeable future actions, regardless of who is responsible for such actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

AIR POLLUTION EFFECTS

The operation of the proposed facility would generate air pollutants from the combustion of natural gas. San Bernardino County has at least 200 point sources of nitrogen oxides, producing over 20,000 tons per year (tpy)(EPA 2002). During operations, the nitrogen oxide contribution of the plant to the air basin is 191 tpy (BEP II 2002a, Tables 7.7-1 and 7.7-12), so BEP II would cause a 0.8 percent increase over the County's yearly total if left unmitigated. The maximum deposition from nitrogen oxides is calculated as 0.27 kg/ha-yr (BEP II 2003b, Data Response 121). In addition to the nitrogen deposition from combustion, the proposed facility has nitrogen deposition from its air scrubbing technology in the form of ammonia. During operations, the BEPII proposes to have an ammonia slip rate of 10 parts per million (ppm)(BEP II 2003b, Data Response 104). The applicant is unwilling to reduce the ammonia slip rate to 5 ppm, and the nitrogen deposition from ammonia at 10 ppm would be 0.649 kg/ha-yr (BEP II 2003b, Data Response 121). At an ammonia slip rate of 5 ppm the applicant estimated the lifetime average ammonia slip would be less than 100 tpy (BEP II 2003b, Data Response 104).

The nitrogen deposition rate considered sufficient to affect ecosystem structure and diversity is 3 to 10 kg/ha/yr depending on vegetation type (Fox et al. 1989). The closest monitoring station for nitrogen deposition is Joshua Tree National Park, about 55 miles to the west. In 2001, Joshua Tree National Park had an annual nitrogen oxide deposition rate of 1.03 kg/ha-yr and an ammonia deposition rate of 0.30 kg/ha-yr (NAD 2001) and a total nitrogen deposition rate of 3.3 kg/ha-yr (CASTNET 2001). So ambient conditions in this desert region are at a level of concern. BEP II emissions, if left unmitigated, would increase ambient levels at the site and immediate area by around 19 percent to 3.949 kg/ha-yr. Biology staff supports any proposed AIR QUALITY conditions of certification which limit the ammonia slip rate to 5 ppm or less to reduce the nitrogen loading on local vegetation and support the use of emission reduction credits to improve regional air quality. At this time, there are no sensitive communities or plants within the plume of the power plant, and thus the impact of ammonia deposition is adverse but not significant.

During the commissioning phase, BEP II's air emission contribution is higher because pollution controls are not in place or are being calibrated. Modeling data estimated that during commissioning, the maximum contribution of nitrogen oxides is 4.3 kilograms per hectare per year (kg/ha-yr) (BEP II 2002g, Data Response 26; BEP II 2002a, Table 7.7-40). Thus, there is a potential doubling of nitrogen deposition in the local area during the commissioning phase. The impact of the deposition would be dependant on the precipitation amounts during the commissioning phase, but is most likely to cause some level of increased foliar development in surrounding vegetation. Staff does not have enough research to make conclusions on long-term nitrogen deposition effects in the Mojave desert, but nitrogen deposition may be a causal factor in the invasions of Mediterranean grasses in coastal sage scrub (Fenn et al. 2003).

Joshua Tree National Park would not likely receive an increase in air pollutants because of its distance from the proposed BEPII project; most of the deposition from operations is on the northern fence line of the facility, with a plume of emission extending north and east of the site for approximately 2 miles before reaching a level that is below the modeling threshold (less than 0.05 μg/m3) (BEP II 2002a, Figure 7.7-10). The National Park Service does not believe that the proposed project will create an adverse impact on visibility or air quality related values at Joshua Tree National Park (Codding 2003). The applicant's proposal to reduce regional air quality impacts with the purchase of emission reduction credits will likely improve air quality at the Park (see AIR QUALITY).

Imperial Irrigation District Transmission Line Upgrades

Imperial Irrigation District is in the process of reviewing a transmission line connection between the Buck Blvd. Substation and Devers Substation (to the east). The transmission line would cross desert tortoise habitat, with observed densities for the area ranging from 75 to greater than 100 adults per square mile (IID/BLM 2003, page 3.1-37) The Desert Southwest Transmission Line would have temporary and permanent impacts to desert tortoise lands (BIOLOGICAL RESOURCES, Table 2). The proposed survey effort and mitigation package for the transmission line should be adequate to identify and address the project impacts, and the project is under consultation with the USFWS. However, crossing the desert within a previously undisturbed transmission line corridor would continue to degrade and fragment the desert. The proliferation of approved utility corridors, along with the attraction of transmission line roads for off-road enthusiast, has resulted in negative impacts to desert tortoise communities which in the past had been isolated from human impacts (Hoff and Marlow 2002, Bury and Luckenbach 2002). These negative impacts are significant for their individual impact as well as collectively because fewer undisturbed desert locations remain as a result of a series of decisions to allow more utility corridors. Because BEP II would be sending its electricity across these new lines, it is linked to this cumulative impact. The efforts of the Desert Tortoise Preserve Committee to purchase and protect lands from future development are an attempt to offset the impacts of utility corridors, but their efforts can never match the scale of the habitat loss which has gone unmitigated for many years.

BIOLOGICAL RESOURCES - Table 2
Habitat Loss from Desert Southwest Transmission Line Proposed Project (IID/BLM 2003, Table 3.1-2)

Activity/ Project Component	Trans. Line Options	Sonoran Creosote Brush (Temp/ Perm)	Desert Dry Wash (Temp/ Perm)	Agricultural Land (Temp/ Perm)	Sonoran Desert Mixed Scrub (Temp/ Perm)	Mojave Creosote Brush Scrub (Temp/ Perm)
Substation/ Switching Station at Hobsonway	230-kV 500 kV	None	25/25 25/25	None	None	None
Devers Substation Modifications	230-kV 500 kV	None	None	None	None	5/5 5/5
Dillion Road Substation	230-kV 500 kV	None	None	None	None	25/25 25/25
Tower Footings	230-kV 500 kV	427/12 366/10	243/7 209/6	13/1 11/1	195/5 167/5	192/5 164/5
Pulling and Tensioning Sites	230-kV 500 kV	26/0 26/0	15/0 15/0	1/0 1/0	12/0 12/0	12/0 12/0
Spur Roads	230-kV 500 kV	11/11 10/10	6/6 6/6	1/1 1/1	5/5 4/4	5/4 5/4
TOTAL	230-kV 500 kV	**464/23** **402/20**	**289/38** **255/37**	**15/2** **13/2**	**212/10** **183/9**	**239/39** **211/39**

MITIGATION

APPLICANT'S PROPOSED MITIGATION

The applicant has proposed in the AFC several impact avoidance measures to reduce impacts to biological resources in the Blythe area (BEP II 2002a). The applicant will:

- Designate a project biologist to manage all biological resource conditions of certification;
- Develop and institute a Worker Environmental Awareness Program to inform construction and operations workers about biological resources associated with the project.

These measures have been incorporated into Conditions of Certification **BIO-1** through **BIO-4**. The project owner will submit these and other measures within a comprehensive mitigation and monitoring document (Condition of Certification **BIO-5**).

During construction, the applicant will continue to implement measures to avoid harm to species such as monitoring open trenches, installing raptor friendly power lines, handling any desert tortoise encountered using the latest protocol, and controlling trash. These measures have been incorporated into Condition of Certification **BIO-6**. The applicant has agreed to monitor the fenceline to ensure integrity and to fix breaks quickly (Condition of Certification **BIO-8**).

During operations, the applicant has agreed to measures to evaluate the level of use at evaporation ponds (see Conditions of Certification **BIO-10** and **BIO-11**). Such measures will allow for assessments of use of the area by wildlife and will highlight if any harm is occurring in a timely manner, but would be inadequate to protect species from harm initially.

STAFF'S PROPOSED MITIGATION

The use of the site by wildlife has been highly-controlled by the installation of a desert-tortoise proof fence along the edge of the project. However, staff determined there was still an opportunity for wildlife to enter the site, much like the kit fox did in March 2003. Therefore, staff proposes a protocol for handling these incidents to ensure biological oversight in actions (Condition of Certification **BIO-9**).

The petition to list the burrowing owl as a state threatened or endangered species earlier this year has placed more emphasis on full mitigation of all impacts. Staff requires the applicant to perform a survey for burrowing owls prior to the start of construction and to mitigate impacts to both active burrows and foraging habitat (Condition of Certification **BIO-12**).

The evaporation ponds are likely to have toxic selenium levels and to be too saline for birds to safely use based on recent literature. Because the power plant facility next to the proposed project has evaporation ponds that will be monitored prior to the start of construction, there will be ample time to evaluate if birds are ingesting unhealthy levels of selenium. The applicant should be prepared however to implement a hazing program or propose a new wastewater disposal method as part of the remedial measures (Conditions of Certification **BIO-10** and **BIO-11**).

Staff is also proposing that the applicant regard the Cultural Resource Area to the north of the power plant as potential wildlife habitat. This area has a gap between the ground level and the fence that allows wildlife access. Thus, any action taking place in the area, including weed control, should be limited and the proper care taken to protect wildlife (Condition of Certification **BIO-13**).

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

To be in compliance with applicable laws, ordinances, regulations and standards, BEP II must obtain three biology-related permits - (1) a USFWS determination on the potential for take of listed species as defined in the ESA, as undertaken by the federal-lead, Western; (2) a CDFG Section 2080.1 Letter of Concurrence and (3) a CDFG Section 2081(b) (Biological Opinion). These documents will identify the mitigation measures required by each agency.

To obtain a USFWS determination, the federal lead for the project, WAPA, has submitted the Biological Assessment, and asked for concurrence with their determination of no effect to desert tortoise. The USFWS has requested additional information before they can make a concurrence. The applicant has met with the USFWS, and is in the process of supplying the information to WAPA and thus USFWS. The applicant is waiting for a response from the City of Blythe regarding Riverside Avenue, before it can submit a response (BEP II 2003b, Data Response 119). The CDFG Section 2080.1 Letter of Concurrence cannot be issued until the finalization of the federal documents. CDFG has been involved in meetings with WAPA and USFWS (October 10, 2002) and should be able to issue this permit within 30 days of the USFWS issuing their decision.

The applicant must make a choice of assuming burrowing owl presence and undergoing 2081(b) consultation, performing the proper surveys prior to staff's issuance of the Final Staff Assessment or possibly delaying construction until the proper breeding and winter surveys can be completed. The CDFG determination on burrowing owl is dependent on the lead agency issuing their permit authorizing the activity. The CDFG has 90 days from the date on which the lead agency approved the activity to issue a 2081(b) permit, but the review can be extended by an additional 60 days if the CDFG determines that additional time is necessary due to the complexity of the application, for a total of 150 days. Because the proposed project would occur in a well-defined space with agency oversight, the CDFG is likely to only need 90 days to complete the permitting.

FACILITY CLOSURE

Sometime in the future, the BEP II will experience either a planned closure, or be unexpectedly (either temporarily or permanently) closed. When facility closure occurs, it must be done in such a way as to protect the environment and public health and safety. To address facility closure, an "on-site contingency plan" will be developed by the project owner, and approved by the Energy Commission Compliance Project Manager (CPM). Facility Closure mitigation measures will also be included in the Biological Resources Mitigation Implementation and Monitoring Plan prepared by the applicant.

Staff does not have any biological resource facility closure recommendations in the event of an unexpected temporary closure of the BEP II. However, in the event that the Energy Commission CPM decides that the facility is permanently closed, the facility closure measures provided in the on-site contingency plan and Biological Resources Mitigation Implementation and Monitoring Plan would need to be implemented.

UNRESOLVED ISSUES AND RECOMMENDATIONS

UNRESOLVED ISSUES

Federal Biological Opinion

Since the project may impact federally listed species, in particular desert tortoise, the consultation and resulting biological opinion under Section 7 of the Federal Endangered Species Act must be completed prior to Hearings. The City of Blythe must issue a letter indicating if construction is needed outside of the fenceline by the applicant before the consultation can be completed. This letter is being held up until there is a Planning Commission Review (PCR) permit from the City planning staff. Staff will continue to work closely with the USFWS in order to address all of their biological resource concerns.

CDFG Biological Opinion/Letter of Concurrence

Since the project may impact state listed species, in particular desert tortoise, the state's Letter of Concurrence must be complete prior to construction. The Section 2080.1 documentation will be issued within 30 days after the CDFG obtains a copy of the Federal Biological Opinion. Staff will continue to work closely with CDFG staff in order to address all of their biological resource concerns relating to desert tortoise.

The petition to state-list the western burrowing owl as threatened or endangered will be voted on in 2003. If the vote is to review the species as a candidate, the species will be treated by CDFG as a state-listed species for one year. This time frame overlaps the BEP II's proceedings. Thus, the applicant must seek protection from the illegal "take" of this state-listed species under Section 2081(b), perform the necessary surveys during this proceeding, or accept a condition which may delay construction until burrowing owls are shown as absent from the site and a buffer around the site.

Interconnection to Transmission Line Grid

The interconnection to the transmission line grid is still being determined. If for some reason the applicant is no longer connecting to a Western Area Power Administration, then the federal nexus for USFWS consultation will be lost. The only alternative for an applicant who is seeking protection from illegal "take" of federally-listed species is to prepare a Habitat Conservation Plan under Section 10 of the Endangered Species Act and submit it for review. Low-impact projects, such as BEP II, can be permitted in around one-year, but it would require a mitigation proposal that was acceptable to USFWS staff from the onset.

CONCLUSIONS

The items that remain outstanding, and which must be confirmed prior to the publication of an FSA for Biological Resources include:

- The applicant must make a choice of assuming presence and undergoing 2081(b) consultation, performing winter and spring burrowing owl surveys during this proceeding, or accepting a condition of certification which may delay construction until the proper breeding and winter surveys can be completed to show absence of burrowing owls; and
- The applicant must have a Biological Assessment that has been accepted as complete by the USFWS.

Staff and various agencies have come to general agreement with the Applicant on the mitigation and compensation that will be necessary to ensure the project is constructed and operated in compliance with various state and federal laws, ordinances, regulations, and standards. Staff concludes that if the mitigation measures discussed above are made conditions of certification, the project will not result in a significant impact on biological resources. Based on this analysis, and discussions with representatives of other agencies, staff recommends the following Biological Resources Conditions of Certification.

CONDITIONS OF CERTIFICATION

Designated Biologist Selection

BIO-1 The project owner shall submit the resume(s), including contact information, of the proposed Designated Biologist and any Biological Monitor(s) to the Compliance Project Manager (CPM) for approval.

Verification: The project owner shall submit the resume and contact information for the Designated Biologist and Biological Monitor(s) to the CPM at least 60 days prior to the start of any site (or related facilities) mobilization. The Designated Biologist must have a through understanding of the Conditions of Certification, the federal and state permits, and the monitoring procedures established in the BRMIMP. Site and related facility activities shall not commence until an approved Designated Biologist is available to be on site and to train all Biological Monitors. Biological Monitor(s) training shall include familiarity with the Conditions of Certification, the federal and state permits, and the monitoring procedures established in the BRMIMP.

The Designated Biologist must meet the following minimum qualifications:

1. Bachelor's Degree in biological sciences, zoology, botany, ecology, or a closely related field;
2. Three years of experience in field biology or current certification of a nationally recognized biological society, such as The Ecological Society of America or The Wildlife Society; and

3. At least one year of field experience with biological resources found in or near the project area.

The Biological Monitor(s) shall have a background in biology or environmental science and be approved by the CPM.

If a Designated Biologist needs to be replaced, the specified information of the proposed replacement must be submitted to the CPM at least ten working days prior to the termination or release of the preceding Designated Biologist. In an emergency, the project owner shall immediately notify the CPM and submit the qualifications of a short-term replacement. The CPM shall approve the short-term replacement within one business day. The short-term replacement shall have all the duties and rights of a Designated Biologist while a permanent Designated Biologist is proposed to the CPM for consideration.

Designated Biologist and Biological Monitor Duties

BIO-2 The project owner shall ensure that the Designated Biologist and Biological Monitor(s) shall perform the following during any site (or related facilities) mobilization, ground disturbance, grading, construction, operation, and closure activities:

1. Advise the project owner's Construction and Operation Managers on the implementation of the biological resources Conditions of Certification;

2. Be available to supervise or conduct mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as wetlands and special status species or their habitat;

3. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions;

4. Inspect active construction areas where animals may have become trapped prior to construction commencing each day. At the end of the day, inspect for the installation of structures that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (parking lots) for animals in harms way;

5. Notify the project owner and the CPM of any non-compliance with any biological resources Condition of Certification; and

6. Respond directly to inquiries of the CPM regarding biological resource issues.

Verification: The project owner shall ensure that the Designated Biologist and Biological Monitor(s) maintain written records of the tasks described above, and summaries of these records shall be submitted in the Monthly Compliance Reports (MCR).

During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

Designated Biologist and Biological Monitor Authority

BIO-3 The project owner's Construction/Operation Manager shall act on the advice of the Designated Biologist or Biological Monitor(s) to ensure conformance with the biological resources Conditions of Certification.

If required by the Designated Biologist or Biological Monitor(s), the project owner's Construction/ Operation Manager shall halt all site mobilization, ground disturbance, grading, construction, and operation activities in areas specified by the Designated Biologist as sensitive or which may affect a sensitive area or species.

The Designated Biologist and Biological Monitor(s) shall:

1. Require a halt to all activities in any area when it is determined that there would be an adverse impact to sensitive species if the activities continued;

2. Inform the project owner and the Construction/Operation Manager when to resume activities; and

3. Notify the CPM if there is a halt of any activities, and advise the CPM of any corrective actions that have been taken, or will be instituted, as a result of the halt.

Verification: The Designated Biologist shall notify the CPM and project owner immediately (and no later than the following morning of the incident, or Monday morning in the case of a weekend) of any non-compliance or a halt of any site mobilization, ground disturbance, grading, construction, and operation activities. The project owner shall notify the CPM of the circumstances and actions being taken to resolve the problem.

Whenever corrective action is taken by the project owner, a determination of success or failure will be made by the CPM within five working days after receipt of notice that corrective action is completed, or the project owner will be notified by the CPM that coordination with other agencies will require additional time before a determination can be made.

Worker Environmental Awareness Program

BIO-4 The project owner shall develop and implement a CPM approved Worker Environmental Awareness Program (WEAP) in which each of its employees, as well as employees of contractors and subcontractors who work on the project site or any related facilities during site mobilization, ground disturbance, grading, construction, operation and closure are informed about sensitive biological resources associated with the project.

The WEAP must:

1. Be developed by or in consultation with the Designated Biologist and consist of an on-site or training center presentation in which supporting written material is made available to all participants;

2. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas;
3. Present the reasons for protecting these resources;
4. Present the meaning of various temporary and permanent habitat protection measures;
5. Identify whom to contact if there are further comments and questions about the material discussed in the program; and
6. Include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines.

The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist.

Verification: At least 60 days prior to the start of any site (or related facilities) mobilization, the project owner shall provide to the CPM two (2) copies of the WEAP and all supporting written materials prepared or reviewed by the Designated Biologist and a resume of the person(s) administering the program.

The project owner shall provide in the Monthly Compliance Report the number of persons who have completed the training in the prior month and a running total of all persons who have completed the training to date.

The signed training acknowledgement forms shall be kept on file by the project owner for a period of at least six months after the start of commercial operation.

During project operation, signed statements for active project operational personnel shall be kept on file for six months following the termination of an individual's employment.

Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP)

BIO-5 The project owner shall submit two copies of the proposed BRMIMP to the CPM (for review and approval) and to CDFG and USFWS (for review and comment) and shall implement the measures identified in the approved BRMIMP.

The final BRMIMP shall identify

1. All biological resources mitigation, monitoring, and compliance measures proposed and agreed to by the project owner;
2. All biological resources Conditions of Certification identified in the Commission's Final Decision;
3. All biological resource mitigation, monitoring and compliance measures required in federal agency terms and conditions, such as those provided in the USFWS Biological Opinion;
4. All biological resources mitigation, monitoring and compliance measures required in other state agency terms and conditions, such as those provided

in the CDFG Incidental Take Permit and Streambed Alteration Agreement and Regional Water Quality Control Board permits;

5. All biological resources mitigation, monitoring and compliance measures required in local agency permits, such as site grading and landscaping requirements;
6. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation and closure;
7. All required mitigation measures for each sensitive biological resource;
8. Required habitat compensation strategy, including provisions for acquisition, enhancement, and management for any temporary and permanent loss of sensitive biological resources;
9. A detailed description of measures that shall be taken to avoid or mitigate temporary disturbances from construction activities;
10. All locations on a map, at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction;
11. Aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities - one set prior to any site or related facilities mobilization disturbance and one set subsequent to completion of project construction. Include planned timing of aerial photography and a description of why times were chosen;
12. Duration for each type of monitoring and a description of monitoring methodologies and frequency;
13. Performance standards to be used to help decide if/when proposed mitigation is or is not successful;
14. All performance standards and remedial measures to be implemented if performance standards are not met;
15. A discussion of biological resources related facility closure measures;
16. A process for proposing plan modifications to the CPM and appropriate agencies for review and approval; and
17. A copy of all biological resources permits obtained.

<u>Verification:</u> The project owner shall provide the specified document at least 60 days prior to start of any site (or related facilities) mobilization.

The CPM, in consultation with the CDFG, the USFWS and any other appropriate agencies, will determine the BRMIMP's acceptability within 45 days of receipt.

The project owner shall notify the CPM no less than five working days before implementing any modifications to the approved BRMIMP to obtain CPM approval.

Any changes to the approved BRMIMP must also be approved by the CPM in consultation with CDFG, the USFWS and appropriate agencies to ensure no conflicts exist.

Within thirty (30) days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written report identifying which items of the BRMIMP have been completed, a summary of all modifications to mitigation measures made during the project's site mobilization, ground disturbance, grading, and construction phases, and which mitigation and monitoring items are still outstanding.

Construction Mitigation Management to Avoid Harassment or Harm

BIO-6 The project owner shall manage their construction site, and related facilities, in a manner to avoid or minimize impacts to the local biological resources.

Measures to be implemented are:

1. Install temporarily fence and provide wildlife escape ramps for construction areas that contain steep walled holes or trenches if outside of an approved, permanent exclusionary fence. The temporary fence shall be hardware cloth or similar materials that are approved by USFWS and CDFG;
2. Ensure all food-related trash is disposed of in closed containers and removed at least once a week.
3. Prohibit feeding of wildlife by staff or contractors;
4. Prohibit non-security related firearms or weapons from being brought to the site;
5. Prohibit pets from being brought to the site;
6. Report all inadvertent deaths of sensitive species to the appropriate project representative. Injured animals shall be reported to CDFG and the project owner shall follow instructions that are provided by CDFG. . All incidences of wildlife injury or mortality resulting from project-related vehicle traffic on roads used to access the project shall be reported in the MCR;
7. Minimize use of rodenticides and herbicides in the project area;
8. Cover selected electrical equipment with the potential to electrocute wildlife within the substation with appropriate UV resistant material;
9. Shield lighting to prevent off-site impacts and limit its use during night-time construction to only what is necessary for safety;
10. Install power lines following Avian Power Line Interaction Committee's guidelines; and
11. Follow the July 1999 (or most current) desert tortoise handling procedures whenever a desert tortoise is encountered.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP.

Exotic Weed Control Program

BIO-7 A comprehensive exotic control program for California Department of Agriculture List A, List B, and Red Alert weeds, shall be implemented at the 76-

acre power plant site. This program shall be implemented until such time that the adjacent land use on the north and west sides in no longer a natural community or agriculture, or until the plant is permanently closed. The natural vegetation adjacent to the BEP II site shall be monitored to determine if it has been modified or degraded. Any seed mixture applied following ground disturbance shall be certified as weed-free.

Verification: The project's Designated Biologist shall submit a report to the CPM for approval. The report shall include photos of the adjacent land or otherwise document any changes in an annual report until such time as the CPM approves cessation. The Designated Biologist shall submit the seed mixture to be used following ground disturbance.

Fence Monitoring

BIO-8 The project owner shall conduct maintenance monitoring of the wildlife exclusion fencing on a monthly basis and complete repairs within one week of a problem being identified. Temporary fencing must be installed at any gaps if it shall remain open overnight.

Verification: The project owner shall submit records of all monitoring dates, identify the locations that required repair, and any corrective actions taken in the MCR and Annual Compliance Report.

BIO-9 The Designated Biologist and CPM shall be contacted within 24-hours if wildlife is found within the fenceline during construction. Actions to prevent harm shall immediately be taken. The local office of the California Department of Fish and Game shall be contacted if wildlife is found within the fenceline during operations.

Verification: For any wildlife found within the fenceline during construction a report shall be completed by the Designated Biologist and submitted with the MCR. For any wildlife found within the fenceline during operations, a report shall be completed by the plant manager and submitted with the Annual Compliance Report.

Evaporation Pond Monitoring

BIO-10 Following the start of operations, both cells of the evaporation ponds shall be monitored twice monthly (once every two weeks, two weeks apart) by the Designated Biologist or a CPM-approved individual who can identify birds of the area. Records shall be made of the type of birds (e.g, waterfowl, shorebirds, etc.), number of birds, and behavior. If a substantial number of bird and wildlife are found to be using the ponds, remedial actions to reduce bird use must be implemented. The project owner shall submit an Evaporation Pond Monitoring Report to the CPM four times a year (every three months). This monitoring shall continue for the first three years of plant operation, and depending on the results, could be discontinued after consultation with the CPM or continue as needed.

Verification: Thirty (30) days prior to the start of operations, the project owner shall provide copies of the Evaporation Pond Monitoring Plan and all supporting materials to the CPM for approval. The Plan shall clearly identify the amount of bird use sufficient to invoke remedial actions to reduce bird use. The Plan shall include survey methodology and performance standards to be used to help decide if/when proposed remedial actions are or are not successful and remedial measures to be implemented if performance standards are not met. All bird use indices, thresholds and remedial actions to be taken must be approved by the CPM, in consultation with California Department of Fish and Game and the U.S. Fish and Wildlife Service. An Evaporation Pond Monitoring Report shall be submitted to the CPM every three months. In the Evaporation Pond Monitoring Report, the project owner shall submit records of all monitoring dates, data collected, and any corrective actions taken. The Report shall be sent to the Federal Aviation Administration, City of Blythe, Blythe Airport Staff, ALUC, California Department of Fish and Game, U.S. Fish and Wildlife Service, and the CPM. The monitoring must continue until the applicant is given written approval from the CPM to stop.

BIO-11 The water quality in the evaporation ponds shall be monitored monthly for the first three years of operation for constituent concentrations. Collections of invertebrates shall be taken from each cell in the evaporation pond every three months, and these samples shall be tested for selenium concentrations. Selenium concentrations in water which exceeds 0.005 mg/L and concentration in aquatic invertebrates which exceed 3 parts per million (dry weight) shall be considered hazardous to wildlife. The project owner shall submit an Evaporation Pond Monitoring Report to the CPM four times a year (every three months). This monitoring shall continue for the first three years of plant operation, and depending on the results, could be discontinued at that time or continues as needed after consultation with the CPM.

Verification: Thirty (30) days prior to the start of operations, the project owner shall provide copies of the Evaporation Pond Monitoring Plan and all supporting materials to the CPM for approval. The Plan shall clearly identify which constituent concentrations shall be monitored. An Evaporation Pond Monitoring Report shall be submitted to the CPM every three months. In the Evaporation Pond Monitoring Report, the project owner shall submit records of all monitoring dates, certified laboratory results, and any corrective actions taken. The Report shall be submitted to the Federal Aviation Administration, City of Blythe, Blythe Airport Staff, ALUC, California Department of Fish and Game, U.S. Fish and Wildlife Service, and the CPM.

Burrowing Owl Surveys and Compensation for Impacts

BIO-12 The project owner shall survey for burrowing owl activities to assess owl presence and need for further mitigation. Active burrows shall be monitored by the Designated Biologist or Biological Monitor(s) throughout construction to identify additional losses from nest abandonment. The project owner shall protect lands and enhance or install burrows to compensate for impacts to active burrows at the site, along related facilities, or within 150 feet of these features. The project owner shall protect lands to compensate for permanent losses of potential upland foraging habitat.

Verification: The project owner shall survey for burrowing owl activities to assess owl presence and need for further mitigation 30 days prior to site mobilization. If construction is delayed or suspended for more than 30 days after the survey, the area shall be resurveyed. Surveys shall be completed for occupied burrows at the fenced parcel and for a 500 foot buffer around these features (where possible and appropriate based on habitat). All occupied burrows shall be mapped on an aerial photo. At least 15 days prior to the expected start of any project-related ground disturbance activities, or restart of activities, the project owner shall provide the burrowing owl survey results and mapping to the CPM and CDFG.

Based on the burrowing owl survey results, the following three actions shall be taken by the project owner to offset impacts during construction:

1) Where a burrowing owl is sighted:

   a) If paired owls are present in areas scheduled for disturbance or degradation (e.g., grading) or within 150 feet of a permanent project feature, and nesting is not occurring, owls are to be removed per CDFG-approved passive relocation. Passive relocation is only acceptable typically from September 1 to January 31, to avoid disruption of breeding activities. The specific dates for acceptable passive relocation are dependent on the end of burrowing owl nesting season during that calendar year.

   b) If paired owls are present within 150 feet of a temporary project disturbance (e.g., transmission line stringing), active burrows shall be monitored by the Designated Biologist or Biological Monitor(s) throughout construction to identify additional losses from nest abandonment and/or loss of reproductive effort (e.g., killing of young).

   c) If paired owls are nesting in areas scheduled for disturbance or degradation, nest(s) shall be avoided from February 1 through August 31 by a minimum of a 250-foot buffer or until fledging has occurred. The specific dates for acceptable passive relocation are dependent on the end of burrowing owl nesting season during that calendar year. Following fledging, owls may be passively relocated.

2) Based on the actions taken during construction, the project owner shall provide a land protection and monitoring proposal for CPM approval, and to the CDFG for review 60 days prior to commercial operation. The land protection shall be based on the following premises:

   d) To offset the loss of active foraging and burrow habitat, the project owner shall provide 6.5 acres of protected lands within the Blythe area for each pair of owls or unpaired resident bird that was passively relocated or for which project-related disturbance caused nest abandonment and/or loss of reproductive effort (e.g., killing of young). Protection of additional habitat acreage per pair or unpaired resident bird may be applicable in some instances (such as for gross negligence on the part of the project owner or a contractor).

   e) To offset the permanent loss of potential foraging and burrow habitat, the project owner must provide 0.5 acre of land within the Blythe Area for every acre of suitable habitat they permanently converted to an unsuitable use (e.g., ponds or buildings) that was within 300 feet of a burrowing owl pair or unpaired resident.

   f) The project owner’s protected lands shall be within 1,800 feet of occupied burrowing owl habitat.

g) For each occupied burrow destroyed during construction, existing unsuitable burrows on the protected lands shall be enhanced (e.g., cleared of debris or enlarged) or new burrows installed at a ratio of 2:1.

h) The project owner must provide funding for long-term management and monitoring of protected lands based on the Center for Natural Lands Management Property Analysis Record, or similar cost analysis program.

3) Within 30 days prior to the start of commercial operation, the project owner shall submit to the CPM two copies of the relevant legal paperwork that protects lands in perpetuity (e.g., a conservation easement as filed with the Riverside County Assessor), and any related documents which discuss the types of habitat protected on the parcel. If a private mitigation bank is used, the project owner shall provide a letter from the approved land management organization stating the amount of funds received, the amount of acres purchased in long term management, and their location.

Future Work on Cultural Resources Area

BIO-13 The project owner shall prohibit habitat disturbance in the Cultural Resources Area unless all regulatory parties have been adequately notified in writing and have given approval. The use of pick-up trucks and automobiles shall be limited and shall only be operated during the daylight hours. All persons entering the site must have completed the Worker Environmental Awareness Program.

Verification: A summary of any activities in the Cultural Resource Area shall be made part of the annual reporting to the CPM. All dates of entry and purpose, a copy of signed training acknowledgement forms, and a report on any wildlife sightings shall be part of the annual report. The project owner shall notify the Commission, Western Area Power Administration, U.S. Fish and Wildlife Service, and California Department of Fish and Game 60 days prior to any proposed construction in the Cultural Resource Area. Thirty (30) days prior to construction, the Cultural Resource Area shall be fenced in a manner that excludes desert tortoise with a biological monitor present. A clearance survey for desert tortoises within the fenceline must be completed prior to commencing work within the fenceline. The results of the desert tortoise clearance survey shall be sent to the same parties listed above for review and comment prior to initiating construction within the fenceline.

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CULTURAL RESOURCES

Gary Reinoehl

INTRODUCTION

This cultural resources section identifies potential impacts of the proposed Blythe Energy Project Phase II (BEP II) cultural resources, as defined under state and federal law. The primary concern in cultural resources analysis for this project is to ensure that all potential impacts are identified and that conditions are set forth that ensure that impacts are mitigated below a level of significance under the California Environmental Quality Act (CEQA) and under the National Environmental Policy Act (NEPA).

Staff provides a cultural overview of the project, as well as analyses of potential impacts from the project using criteria from the CEQA and the National Historic Preservation Act (NHPA). If cultural resources are identified, staff determines whether there may be a project related impact to identified resources and if the resource is eligible for the California Register of Historic Resources (CRHR) or the National Register of Historic Places (NRHP). If the resources are eligible for either register, staff recommends mitigation that attempt to ensure that no significant impacts will occur and that will reduce impacts to the cultural resource to a less than significant level, if possible.

There is always a potential that a project may impact a previously unidentified resource or may impact an identified historical resource in an unanticipated manner. Staff therefore recommends procedures in the conditions of certification that mitigate these potential impacts.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following laws, ordinances, regulations, standards, and policies apply to the protection of cultural resources in California. Projects licensed by the Energy Commission are reviewed to ensure compliance with these LORS.

FEDERAL

- Code of Federal Regulations, 36 CFR Part 61. Federal Guidelines for Historic Preservation Projects: The U.S. Secretary of the Interior has published a set of Standards and Guidelines for Archaeology and Historic Preservation. These are considered to be the appropriate professional methods and techniques for the preservation of archaeological and historic properties. The Secretary's standards and guidelines are used by federal agencies, such as the Forest Service, the Bureau of Land Management, and the National Park Service. The State Historic Preservation Office refers to these standards in its requirements for mitigation of impacts to cultural resources on public lands in California.
- Code of Federal Regulations, 36 CFR Part 800 et seq., the implementing regulations of Section 106 of the National Historic Preservation Act, 16 U.S.C. § 470 requires federal agencies to take into account the effects of their undertakings on historic properties through consultations beginning at the early stages of project planning. The regulations implementing this act, which were revised in 1997, set forth

procedures to be followed for determining eligibility of cultural resources, determining the effect of the undertaking on the historic properties, and how the effect will be taken into account. The eligibility criteria and the process described in these regulations are used by federal agencies. Very similar criteria and procedures are used by the state in identifying cultural resources eligible for listing in the California Register of Historical Resources.

STATE

- California Code of Regulations, Title 14, section 4852 defines the term "cultural resource" to include buildings, sites, structures, objects, and historic districts.
- Public Resources Code, Section 5000 establishes the California Register of Historical Resources (CRHR), establishes criteria for eligibility to the CRHR, and defines eligible resources. It identifies any unauthorized removal or destruction of historic resources on sites located on public land as a misdemeanor. It also prohibits obtaining or possessing Native American artifacts or human remains taken from a grave or cairn and establishes the penalty for possession of such artifacts with intent to sell or vandalize them as a felony. This section defines procedures for the notification of discovery of Native American artifacts or remains, and states that it is the policy of the State that Native American remains and associated grave artifacts shall be repatriated.
- The California Environmental Quality Act (CEQA) (Public Resources Code, section 21000 et seq.; Title 14, California Code of Regulations, section 15000 et seq.) requires analysis of potential environmental impacts of proposed projects and requires application of feasible mitigation measures.
- Public Resources Code section 21083.2 states that the lead agency determines whether a project may have a significant effect on “unique” archaeological resources; if so, an Environmental Impact Report (EIR) shall address these resources. If a potential for damage to unique archaeological resources can be demonstrated, the lead agency may require reasonable steps to preserve the resource in place. Otherwise, mitigation measures shall be required as prescribed in this section. The section discusses excavation as mitigation; limits the Applicant’s cost of mitigation; sets time frames for excavation; defines “unique and non-unique archaeological resources;” and provides for mitigation of unexpected resources. [The California Energy Commission process is a CEQA equivalent process and Staff Assessments replace the CEQA environmental documents.]
- Public Resources Code section 21084.1 indicates that a project may have a significant effect on the environment if it causes a substantial adverse change in the significance of a historic resource. The section further defines a “historic resource” and describes what constitutes a “significant” historic resource.
- CEQA Guidelines, Title 14, California Code of Regulations, section 15126.4(b), prescribes the manner of maintenance, repair, stabilization, restoration, conservation, or reconstruction as mitigation of a project’s impact on a historical resource; discusses documentation as a mitigation measure; and discusses mitigation through avoidance of damaging effects on any historical resource of an archaeological nature, preferably by preservation in place, or by data recovery

through excavation if avoidance or preservation in place is not feasible. Data recovery must be conducted in accordance with an adopted data recovery plan.

- CEQA Guidelines, section 15064.5 defines the term “historical resources,” explains when a project may have a significant effect on historic resources, describes CEQA’s applicability to archaeological sites, and specifies the relationship between “historical resources” and “unique archaeological resources.” Subsection (f) directs the lead agency to make provisions for historical or unique archeological resources that are accidentally discovered during construction.
- Penal Code, section 622 1/2 states that anyone who willfully damages an object or thing of archaeological or historic interest is guilty of a misdemeanor.
- California Health and Safety Code, section 7050.5 states that if human remains are discovered during construction, the project owner is required to contact the county coroner.

LOCAL

Riverside County

The County of Riverside protects cultural resources by reviewing development applications for compliance with CEQA. More specifically, the Riverside County Comprehensive General Plan Land Use Standards require the Planning Department to determine whether proposed development will alter or destroy an historical site or an archaeological site, cause a substantial adverse change in the significance of an historical or archaeological resource (cf. California Code of Regulations 15064.5), disturb any human remains, or restrict existing religious or sacred uses.

- Riverside County’s General Plan identifies two objectives for Historic and Prehistoric Resources. The first objective requires that significant historic and prehistoric resources are identified and documented, and that there are provisions for the preservation of representative and worthy examples. The second objective recognizes the value of these resources and requires that land uses be assessed for impacts to these resources. Cultural resources technical reports submitted to the County must follow a required outline and the consultant must be pre-qualified to submit reports to the County.
- In addition, Riverside County’s Ordinance 578, which was intended to create and protect historic districts within the county, addresses a desire on the part of the County to preserve its heritage. The Ordinance does not specifically address archeological resources or historic resources outside designated districts.

City of Blythe

The General Plan of the City of Blythe establishes four goals for cultural resources (BEP II 2002a, Table 7.1-3):

1. To protect and preserve important and unique resources of the City and region, thereby maintaining the City residents and Palo Verde Valley’s cultural heritage.

2. Review and evaluate proposals for development to determine the potential for impacts to known and suspected cultural resources of importance, in order to determine mitigation where necessary.

3. Treat archaeological resource information as confidential in order to prevent vandalism and other threats to those resources.

4. Require a professional archeologist be employed to examine and document any resources discovered during construction, and to develop appropriate mitigation measures.

ENVIRONMENTAL SETTING

The project as proposed would be located on the Palo Verde Mesa adjacent to the Blythe Airport, approximately five miles west of the City of Blythe. The project site consists of relatively flat terrain that is sparsely vegetated with desert scrub. The project is contained within the 152-acre Blythe Energy Project Phase I amended site which will contain the proposed power plant and associated facilities. The project site is currently private land bordered on the east by originally permitted Blythe Energy Project, Phase I (BEP I), on the south by Hobsonway a county road, and on the north by Riverside Avenue. Presently, several electric transmission lines (Blythe-Eagle Mountain, Imperial Irrigation District “F”, and Blythe-Knob) consisting of wood pole H-frame structures, cross the property (BEP II 2002a, pp. 7.1-1, 7.1-7).

Refer to the **PROJECT DESCRIPTION** section of this Preliminary Staff Assessment for additional information and maps of the project development region and the project area. The City of Blythe has not yet determined through their planning process whether additional ground disturbing activities would be required outside of these boundaries.

PREHISTORIC SETTING

Paleo-Indian Period

The first well-dated Native American occupation of the Colorado River Valley is the San Dieguito complex, dating between 7,000 and 12,000 years before present (BP). It is assumed from the material culture remains that these people employed a hunter-gatherer adaptation based on small mobile bands exploiting game and collecting seasonally available wild plants. Settlement patterns indicate sites typically located on mesas and terraces overlooking larger washes and around the edges of lakes. Early San Dieguito tools include bifacial and unifacially reduced choppers and chopping tools, concave-edged scrapers, bilateral-notched pebbles, and scraper planes. Later, finely made blades, smaller bifacial points, and a variety of scraper and chopper types were introduced. Finally, fine pressure flaking techniques, including pressure-flaked blades, leaf-shaped projectile points, scraper planes, plano-convex scrapers, crescents (amulets), and elongated bifacial knives become part of the inventory (CEC 2000, p. 125).

Archaic Period

Few Archaic period sites have been dated in the desert on either side of the Colorado River but sites from this time period date between about 7,000 and 1,000 years BP. The economy can be seen as exploitation of a variety of food resources, including large and small animals. Generally, the Archaic period in the Western United States saw a diversification of artifact assemblages, including the introduction of the widespread use of ground stone technology to exploit seasonally available seeds and nuts. However, evidence is lacking in the Lower Colorado River area (CEC 2000, pp. 125, 126).

Late Prehistoric Period

The Late Prehistoric period in the lower Colorado River Region has been referred to as "Patayan" first recognized with the introduction of pottery approximately 1,200 years ago. The presence of Desert Side-notched and Cottonwood type projectile points at about 1,500 years BP may indicate an early pre-ceramic phase. The introduction of floodplain agriculture, the bow and arrow, and a change in burial practices characterizes this period. Population growth, along with more sedentary villages, resulted from a heavy reliance on grown foods rather than wild foods. An extensive trail system across the desert was established that linked the Lower Colorado River peoples with related groups in the greater Southwest, the Gulf of California and the Pacific Ocean. Trails are often associated with ceramic "pot-drops," shrines, and other evidence. Many of the Colorado Desert pictographs, petroglyphs, and bedrock grinding surfaces are also associated with the Patayan pattern. Away from the Colorado River, higher elevations were used for desert resource collection, particularly during periods of flooding. Wild foods are estimated to have accounted for 40 to 70 percent of the diet (CEC 2000, p. 126).

ETHNOGRAPHIC BACKGROUND

Several ethnohistoric and contemporary Yuman and Numic speaking peoples are known for the lower Colorado River region. Yuman groups included the Mojave, Quechan, Hualapai, Havasupai, Yavapai, Kamia, Maricopa, Halchidhoma, Cocopah, and Paipai. Numic groups include the Chemehuevi and the closely-related Southern Paiute. Warfare and migration characterized this period and population boundaries shifted regularly. Before about 1700, the exact group occupying the project area is unknown but it is likely that it was the Maricopa. Sometime after 1700, the Halchidhoma settled the area, living tenuously between the powerful and militant Quechan to the south and the Mojave to the north.

Halchidhoma and Maricopa may be regarded as closely related; two groups interacted extensively and spoke similar dialects. These two groups were also similar in many ways to the Quechan and the Mojave. The Quechan lived in dispersed rancherias along the Colorado River north and south of the confluence with the Gila River. Like the Mojave, large permanent semi-subterranean houses were occupied in the winter, and ramadas or brush shades were used in the summer. Under constant attack by the Quechan and Mojave, the Halchidhoma fled the area for northern Mexico and then the Gila River around 1828. The aggressive Mojave followed them into their former territory and occupied it briefly. The "core" area of the Mojave was the Mojave Valley but did extend north to Old Cottonwood Island, about 15 miles north of Davis Dam, and as far south as the Colorado River Indian Reservation when they were first encountered by the Juan de Oñate expedition in 1604. Occasionally and intermittently they controlled areas as far south as Palo Verde. The Mojave later invited another of their confederates, the Numic speaking Chemehuevi, to settle the area.

The Chemehuevi (and Southern Paiute) were organized into small, mobile groups whose settlement patterns were influenced heavily by seasonal availability of plant resources. Chemehuevi groups moved throughout the desert to exploit plant resources as they became available. They fragmented into nuclear families when food was scant or dispersed but also came together on occasion for game drives. They resided in the Chemehuevi Valley and the Colorado River Valley by 1859. When Chemehuevi groups gained access to land on the Colorado River, they quickly adopted floodwater farming. This group dominated until displaced by Euro-American settlement.

The Halchidhoma, Maricopa, Mojave, Quechan, Chemehuevi, and other groups of the lower Colorado River region shared traits including patrilateral or bilateral descent, an emphasis on personal dreams, cremation of the dead, and floodwater agriculture. They typically lived in settlements widely scattered over the floodplain and adjacent low terraces of the Colorado River. Adjacent higher terraces were used for hunting and gathering wild desert foods. Annual flooding deposited layers of rich silt and provided for the growing of crops such as maize, tepary beans, pumpkins, gourds, and sunflowers. Later, Euro-American introduced wheat, barley, muskmelons, and cowpeas. People relied to some extent on stored supplies of maize and beans, as well as wild foods of the desert. Important wild foods included mesquite, screwbean, tule roots and sprouts, chia, yucca fruits, and agave. Rabbits, squirrels, chipmunks, gophers, woodrats, quail, duck, mudhen, and pigeon were hunted for meat, as well as large game such as deer and mountain sheep. Fishing was also common in the late summer when the river receded.

In addition to local resources, people relied to some degree on regional exchange of goods. The Quechan traded pumpkins, beans, melons, gourds, and maize and received rabbit skin blankets, baskets, buckskins, mescal and finished leather goods from the Yavapai, woven blankets from the Hopi, acorns from the Kumeyaay and Cahuilla, eagle feathers from the Mojave, and tobacco from the Kamia or eastern Kumeyaay.

Yuman contact with Europeans first occurred in 1540 when Hernando de Alacron sailed up the Colorado River to near present-day Yuma, Arizona. However, missions were not established in the region until the late eighteenth century. Once European settlement occurred, conflicts increased in scale and frequency (CEC 2000, pp. 126, 127).

HISTORIC SETTING

Europeans first entered what is now southeastern California in 1540 when Hernando de Alacron sailed up the Colorado River from the Gulf of California to the vicinity of present day Yuma, Arizona. They met and interacted with the Yuman speaking Native Americans who had occupied the area for some time. Contact between these groups continued over the next two centuries, but the Spanish largely focused their colonizing efforts on areas to the south and east. It was not until missions were established in the region in the late eighteenth century that Yuman cultures were directly affected by

Spanish incursion. Conflicts increased in scale and frequency, but the Yumans resisted Spanish domination (CEC 2000, pp. 127, 128).

Anglo-American settlers entered the region following the Mexican War and the Gold Rush in the late 1840's. Fort Yuma was established in 1852 and six years later, the U.S. Army defeated the combined forces of the Mojave and Quechan. Following the pacification of the region, miners, farmers, and cattle ranchers arrived in increasing numbers (CEC 2000, p. 128).

In 1874, San Francisco millionaire Thomas H. Blythe applied for land rights in the Palo Verde Valley under California's Swamp and Overflow Act of 1868, which gave land that was perennially swamp or subject to flooding to anyone who would fill, drain, or put the land to good use. Blythe later obtained 35,971 additional acres under the Federal Desert Land Act in 1877, becoming the dominant private land owner in the valley. Blythe applied for 190,000 miner's inches of Colorado River Water on July 17, 1877, increasing the amount to 385,000 miner's inches by February 15, 1883. In 1879, civil engineer Oliver P. Callaway, partner of Blythe, began digging canals and set up an experimental farm, known as the Colorado Colony. This marked the beginnings of irrigated agriculture in the Palo Verde Valley. By 1904, the town of Palo Verde was a small hamlet, and a store and post office were established. Steamboats along the Colorado River were the primary means of transportation to and from Blythe until 1908, when the Laguna Dam was built above Yuma. Stages handled the need to move people and goods thereafter. However, despite growth, flooding of the Colorado River continued to impede agricultural efforts. It was not until the mid-1930s and the construction of Hoover Dam that flooding was finally controlled (CEC 2000, p. 128).

Transportation routes were continually improved. The railroad had never entered the valley so overland transportation was dominated by roads and trails. Finally, a railroad spur was built to Blythe Junction, and it was extended to Blythe itself in 1915. Most early roads followed the railroad tracks or old wagon roads. The federal highway, now Interstate 10, was paved from Indio to Blythe in 1936 (CEC 2000, p. 128).

During the Depression of the 1930s, most of the immigrants looked for work in agriculture, while some worked in mining. Several large water projects, such as the All-American Canal, were undertaken with the help of the large pool of inexpensive labor. At the start of World War II, the Blythe Municipal Airport was taken over by the U.S. Army and designated Morton Air Academy; 650 buildings and 8,000 foot long runways were constructed. The airport became the home to the 390th Bomb Group, consisting of four squadrons of B-17 Flying Fortresses. The Air Academy served about 8,000 men and several hundred WACs. Wives and families of servicemen swelled the population of Blythe to over 4,000, many living in box cars, sheds, spare rooms, and empty buildings (CEC 2000, p. 128).

During the same period, the U.S. Army Ground Forces established the Desert Training Center (DTC) and was renamed the California-Arizona Maneuver Area (C-AMA) in 1943. The DTC/C-AMA was an armored training facility for the preparation of troops for the invasion of North Africa. The facility covered over 18,000 square miles and served in excess of one million troops. The Blythe Army Air Base, in the middle of DTC/C-AMA, was likely used for transportation and supply purposes. Training at the DTC/C-

AMA continued until 1944, and the Morton Air Academy ceased military training operations in the same year. The airfield returned to its former role as municipal airport, with much improved runway and support buildings. The facility has been used by Palo Verde Valley High School, and later Palo Verde College. The barracks were used as dormitories by the male college students until the college found new facilities (CEC 2000, pp. 128, 129).

RESOURCES INVENTORY

Literature and Records Search

Prior to preparation of the AFC, the Applicant conducted a cultural resources literature search and reviewed site records and maps for the project area at the Eastern Information Center of the California Historic Resources Information System (CHRIS) located at the University of California, Riverside on September 8, 1999 (BEP II 2002a, Appendix 1). The records searches included the energy center site and one mile radius around the project site (BEP II 2002a, p. 7.1-8, Appendix 7.1). Several surveys were conducted in conjunction with the Blythe Energy Project, Phase I.

The surveys included the 76-acre parcel for the Blythe energy Project, Phase I (east half of the current project area), the 76-acre expansion area (west half of the current project area), and an area along and to the north of Riverside Drive. Table 1 indicates the resources that were recorded and their status. Government Land Office maps depicting 19th century features were checked for pertinent features that could be considered cultural resources. Only one trail was noted that is about five miles east of the project area.

Field Surveys

BEP Plant Site

As part of the BEP I, the Request to Add 10 Acres to the Site of the Blythe Energy Project (99-AFC-8C) and the Proposed Amendment to Place Earth Fill from the Blythe Energy Project (99-AFC-8C) an intensive pedestrian survey of the property was completed. The survey of the 76-acre BEP I site revealed four historic sites and three isolated prehistoric artifacts (Table 1). The three isolated prehistoric artifacts found on the plant site consist of a single flake, a scraper tool, and core of chert. Four archeological deposits (CA-RIV-6366H, -6367H, -6368H, and -6369H) recorded in the BEP I site area were determined to not meet the criteria for eligibility for the CRHR (Table 1) (BEP II 2002a, p. 7.1-8; CEC 2001a, p. 217).

Two archeological deposits, CA-RIV-6725H and –6370H, were recorded within the BEP I expansion areas (10 Acre and Earth Fill Amendment). The recording and subsurface testing of CA-RIV-6725H recovered the information values that the deposit contains and the deposit no longer meets the criteria for eligibility for the CRHR (BEP 2002a, p. 7.1-12; CEC 2001b, p. 3).

CA-RIV-6370H is a large historic period deposit associated with the historic military use of the Blythe Army Air Base and/or the Desert Training Area. Extensive testing was

Table 1 Cultural Resources within the Blythe Energy Center Phase I		
Resource Designation	Site Type	Previous determination of Eligibility
CA-RIV-6366H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6367H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6368H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6369H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6370H	Refuse scatter	Potentially eligible, federal MOA (BEP I Am.*)
CA-RIV-6725H	Refuse scatter	Not eligible (BEP I Am.)
P-33-9187	Isolated flake	Not eligible (BEP I)
P-33-9188	Isolated tool	Not eligible (BEP I)
P-33-9189	Isolated core	Not eligible (BEP I)
P-33-9190	Isolated mano	Not eligible (BEP I)
Blythe Airport	WWII air base	Recommended eligible, setting diminished (BEP I)
Parker-Blythe No. 1 and No. 2 lines	Transmission line	Not eligible (BEP I)
Blythe-Knob line	Transmission line	Not eligible (BEP I)
Imperial Irrigation District "F" line	Transmission line	N/A (BEP I)

* BEP I Amendment to place earth fill from the Blythe Energy Project (CEC 200b1, pp. 3, 4)

conducted at CA-RIV-6730H and the applicant provided a draft report indicating that the deposit was eligible for the NRHP. The southern portion of the site consists of landform modifications (grading, trenching, and push piles) with few artifacts. The northern portion of the site consists of trenches, push piles, holes, dirt piles, and many artifacts.

Western Area Power Administration (Western) as the lead federal agency consulted with the California State Historic Preservation Officer (CA SHPO) in accordance with their Section 106 responsibilities under the National Historic Preservation Act for the expansion area. The CA SHPO did not agree that CA-RIV-6370H was eligible for the NRHP and requested additional information. A Memorandum of Agreement was signed by the owner of BEP I, the property owner of the expansion area, the CA SHPO and Western to fulfill Westerns obligations under the federal regulations. The eligibility of CA-RIV-6370H is to be resolved as part of the agreement (BEP II, 2002a, p. 7.1-14).

The Energy Commission staff stated in the amendment analysis, based on the draft testing report, that the information was not sufficient to clearly conclude that CA-RIV-6370H is eligible for the CRHR. CA-RIV-6370H is being treated as eligible until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility for the NRHP and CRHR can be clearly made.

The artifacts and landform alterations that make up the southern portion of CA-RIV-6370H were recorded so that any values that might be contained in the deposit and landscape modifications were recovered. Documentation that sufficient information was gathered to complete a report on the southern portion of CA-RIV-6370H has been provided to the Energy Commission. The final report on the southern portion of the site was accepted on May 21, 2003.

The BEP I project also provided an inventory and evaluation of buildings and structures from the historic period. The inventory included all structures more than 45 years old within a mile of the BEP I project. Three transmission lines were evaluated as not meeting the eligibility criteria for either the NRHP or the CRHR (CEC 2001a, p. 220).

The Blythe Airport was recommended as eligible for the NRHP by the BEP I for its role in World War II activities as Morton Air Base. The setting for the air base has been altered by removal of buildings at the base, intrusions of center-pivot irrigation fields, construction of the Interstate, and the addition of a residential area nearby (CEC 2001a, p. 220).

Additional surveys may be necessary if the city determines through their planning process that ground disturbing activities would be required outside of the current project area. This would be completed prior to the Final Staff Assessment.

Water Conservation Offset Plan

The Applicant has proposed a voluntary Water Conservation Plan to offset the projects use of Colorado River water pumped as groundwater. The plan would calls for BEP II to fallow land that has been under agricultural use within the last five years to offset the project's annual use of approximately 3300 acre-feet of Colorado River water pumped as groundwater from wells at the plant site. The information provided by the applicant indicates that a value of 4.2 acre-feet of water per acre of land fallowed would be used to calculate the number of acres that would need to be fallowed to offset the projects water use. Based on the proposed WCOP, staff does not foresee any potential impacts to cultural resources.

Native American Contacts

Energy Commission staff contacted the Native American Heritage Commission (NAHC) on August 20, 2002 to obtain a list of Native Americans to be contacted for the project area. The NAHC provided names of contacts for Riverside County (NAHC 2002). Western and the Energy Commission staff prepared to consult together with the interested Native American groups. An ethnographic study is being completed for the project area for the BEP I project. This study may identify sensitive resources that could be impacted by the BEP II project. To avoid delays, Energy Commission staff sent letters to these individuals in January of 2003 which described the project and asked about concerns. No responses have been received. Additional contacts will be made to determine if there are other Native American issues. The results of Native American consultation to identify resources will be concluded in the Final Staff Assessment.

CATEGORIZATION OF IDENTIFIED CULTURAL RESOURCES

Various laws apply to the treatment of cultural resources. These laws require the Energy Commission to categorize cultural resources by determining whether they meet sets of specified criteria. These categories then in turn influence the analysis of potential impacts to the cultural resources and the methods and consultation required to mitigate any such impacts. Federal laws apply when a federal agency takes an action. The project will interconnect with a Western owned substation. As a result, Western qualifies as a federal agency taking an action. Western will ensure compliance with federal regulations.

Under federal law, only historical or prehistoric sites, objects, or features, or architectural resources that are assessed as "significant" in accordance with federal guidelines need to be considered in analyzing potential impacts. The significance of historical and prehistoric cultural resources is based on the criteria for eligibility for nomination to the NRHP, as defined in Title 36, Code of Federal Regulations, section 60.4. If such resources are determined to be significant, and therefore eligible for listing in the NRHP, they are afforded certain treatment under the National Historic Preservation Act. If the resources are determined significant, and therefore eligible for the CRHR, then mitigation measures are implemented under CEQA to reduce the impact to less than significant if possible. Federal agencies are responsible for meeting the requirements of NHPA and the Energy Commission is responsible for meeting the requirements of CEQA.

The National Register criteria state that "eligible historic properties" are: districts, sites, building, structures, and objects that possess integrity of location, design, setting, materials, workmanship, feeling, and association, and that:

a) are associated with events that have made a significant contribution to the broad patterns of our history;
b) that are associated with the lives of persons significant in our past;
c) that embody the distinctive characteristics of a type, period, or method of construction, that represent the work of a master, that possess high artistic values, that represent a significant and distinguishable entity whose components may lack individual distinction; or
d) that have yielded, or may be likely to yield, information important to history or prehistory.

California has adopted a similar set of criteria for assessing resources for the California Register of Historical Resources. The CRHR criteria are noted as 1, 2, 3, and 4 while the NRHP criteria are noted as a, b, c, and d.

Under federal law, cultural resources determined not to be significant, that do not meet the eligibility criteria for National Register are subject to recording and documentation only and are afforded no further treatment. However, occasionally certain resources, although they may not be assessed as "significant," may nonetheless be of local or regional importance such that mitigation may be warranted regardless of their assessed significance. Energy Commission staff and involved federal agencies evaluate the survey reports and site records for any known resources located within or adjacent to the project Area of Potential Effects (APE) to determine whether they meet the eligibility criteria.

The record and literature search and the pedestrian surveys of the proposed project were conducted to identify the presence of any cultural resources. Where cultural resources were identified, additional evaluation was conducted to determine whether the resources are already listed on, or are potentially eligible for listing on, either the NRHP [36 CFR 800] or the CRHR. The determination of eligibility is made in compliance with the applicable provisions of the NHPA.

CEQA Guidelines explicitly require the lead agency (in this case, the Energy Commission) to make a determination of whether a proposed project will affect "historical resources" (Cal. Code Regs., tit. 14. §15064.5). The guidelines provide a definition for historical resources and set forth a listing of criteria for making this determination (Cal. Code Regs., tit. 14 § 15064.5). These criteria are the eligibility criteria for the CRHR and are essentially the same as the eligibility criteria for the NRHP. In addition, as with the NRHP, historical resources must also possess integrity of location, design, setting, materials, workmanship, feeling, and association. Resources eligible for the CRHR may have less integrity than the resources eligible for the NRHP. If the criteria are met and the resource is determined eligible for the CRHR, the Energy Commission must evaluate whether the project will cause a "substantial adverse change in the significance of the historical resource," which the regulation defines as a significant effect on the environment Cal. Code Regs., tit. 14 § 15064.5).

CEQA also contains a section addressing "unique" archeological resources and provides a definition of such resources (PRC, § 21083.2). This section establishes limitations on analysis and prohibits imposition of mitigation measures for impacts to archeological resources that are not unique. However, the CEQA Guidelines state that the limitations in this section do not apply when an archeological resource has already met the definition of an historical resource (Cal. Code Regs., tit. 14 § 15064.5).

The Blythe Airport was recommended as eligible for the NRHP by BEP I for its role in World War II activities as Morton Air Base. The setting for the air base has been altered by removal of buildings at the base, intrusions of center-pivot irrigation fields, construction of the Interstate, and the addition of a residential area nearby (CEC 2001a, p. 220).

Western Area Power Administration (Western) as the lead federal agency consulted with the California State Historic Preservation Officer (CA SHPO) in accordance with their Section 106 responsibilities under the NHPA for the BEP I project. The CA SHPO did not agree that CA-RIV-6370H was eligible for the NRHP and requested additional information. A Memorandum of Agreement (MOA) was signed by the owner of BEP I, the property owner of the expansion area, the CA SHPO and Western to fulfill Westerns obligations under the federal regulations. The eligibility of CA-RIV-6370H is to be resolved as part of the MOA (CEC 2001b, pp. 3, 4).

The Energy Commission staff stated in the Staff Analysis of the Proposed Amendment to Place Earth Fill From the Blythe Energy Project (99-AFC-8C), based on the draft testing report, that the information was not sufficient to clearly conclude that CA-RIV-6370H, a historic World War II era trash dump is eligible for the CRHR. CA-RIV-6370H is being treated as eligible until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility for the NRHP and CRHR can be clearly made. The northern portion of the site within the expansion area would be fenced to limit access and protect the resource (CEC 2001b, pp. 3, 4, 6, 8). As part of the amendment, the southern portion of the site would be graded before dirt would be moved to the expansion area. The southern portion of CA-RIV-6370H consists of push piles, graded areas, and a few artifacts. The southern portion of the CA-RIV-6370H was to be mapped, described, and photographically recorded prior to altering the features (CEC 2001b, pp. 4, 6). The final report on the southern portion of the site was accepted by the Energy Commission on May 21, 2003. Eligibility has not been concluded and the CA-RIV-6370H shall be treated as eligible until its eligibility is resolved.

Native American consultation for the proposed project has not been completed. The consultation is to identify sensitive resources that could be impacted by the project. This will be concluded in the Final Staff Assessment.

ANALYSIS AND IMPACTS

Since project development and construction usually entail surface and subsurface disturbance, the proposed BEP II has the potential to adversely affect both known and unknown cultural resources. Staff has analyzed the potential direct, indirect, and cumulative impacts from the proposed project. Direct impacts are those which may result from the immediate disturbance of resources, whether from vegetation removal, vehicle travel over the surface, earth-moving activities, excavation or demolition. Indirect impacts are those which may result from increased erosion due to site clearance and preparation, or from inadvertent damage or vandalism due to improved accessibility. Cumulative impacts to cultural resources may occur if increasing amounts of land are cleared and disturbed for the development of multiple projects in the same vicinity as the proposed project.

The potential for the project to cause impacts to cultural resources is related to the likelihood that such resources are present and whether they are actually encountered during project development and construction activities. Although the existence of known cultural resources increases the potential for additional resources, the absence of known resources does not necessarily mean that unknown resources will not be encountered and that impacts will therefore not occur.

PROJECT SPECIFIC IMPACTS

Only impacts to eligible cultural resources sites can be potentially significant. The Blythe Airport was recommended as eligible for the NRHP by the BEP I for its role in World War II activities as Morton Air Base. The setting for the air base has been diminished by removal of buildings at the base, intrusions of center-pivot irrigation fields, construction of the Interstate, the addition of a residential area nearby, and the construction of BEP I. The alteration of the setting for the construction of BEP I was not sufficient to materially impair the Morton Air Base if it meets the eligibility requirements for the CRHR or the NRHP (CEC 2001a, p. 220). The alteration of the setting for the proposed project would not be sufficient to materially impair the Morton Air Base.

Energy Commission staff stated in the Staff Analysis of the Proposed Amendment to Place Earth Fill From the Blythe Energy Project (99-AFC-8C) that the information was not sufficient to clearly conclude that archeological site CA-RIV-6370H is eligible for the

CRHR or the NRHP. CA-RIV-6370 H is being treated as eligible until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility for the NRHP and CRHR can be clearly made. BEP II has agreed to restrict all activities within the fenced portion of CA-RIV-6370H, i.e. the intact portion of the site on their property (CEC 2003).

Consultation with Native Americans to identify and evaluate resources is not yet complete. Information regarding any resources that could be impacted will be provided in the Final Staff Assessment. Staff is continuing contacting Native American groups and individuals to identify resources that could be impacted by the project. If there is a resource that qualifies as a Native American sacred site that would be impacted by the project, then mitigation measures would be developed to reduce the impacts to less than significant, if possible.

The City of Blythe has not determined through their planning process whether there would be ground disturbing activities required outside of the project site. This could impact portions of CA-RIV-6370H or deposits that have not yet been identified though the survey process. Decisions by the City and information about resources that could be impacted will be provided in the Final Staff Assessment.

CUMULATIVE IMPACTS

Because there is not yet resolution on impacts on cultural resources as a result of the BEP II project, the cumulative impacts on cultural resources can not yet be resolved. This will be completed in the Final Staff Assessment. Staff would review the City's planning decision to determine whether ground disturbing activities would be required outside the project area. In addition, consultation with Native American groups has not been completed. If cultural resources are identified, mitigation may need to be developed. Ground disturbing activities may occur outside the area previously survey for cultural resources. An additional cultural resources survey may identify cultural resources that would need to be evaluated, if they would be impacted by the project.

Imperial Irrigation District and the Bureau of Land Management are in the process of preparing a joint Environmental Impact Report/Environmental Impact Statement (EIR/EIS) for an alternative transmission line between Blythe and either Palm Springs or Niland, which both have large substation facilities. The transmission lines would cross areas where many cultural resources exist. Construction of new utility lines and the accompanying maintenance roads may attract off-road enthusiasts. This could result in indirect impacts to resources by improving access and resulting in collection of artifacts, vehicular erosion, or noise intrusions in sensitive areas. Such negative impacts could be significant as a result of a decision to allow more utility corridors.

FACILITY CLOSURE

At the time of planned closure, all then-applicable LORS will be identified and the closure plan required by the Energy Commission will address compliance with these LORS. Generally, if no additional ground disturbance occurs during closure activities and all conditions of certification have been met, no impacts to cultural resources would be expected. However, actual potential impacts are likely to depend upon the final location of project structures in relation to existing resources, and upon the procedures used for the removal of project structures. Since the spatial relationship between the closure and removal of project structures and sensitive resources cannot be determined at this time, no conclusion can be drawn at this time with respect to the impact of facility closure on cultural resources. The closure plan, when created, will address impacts to cultural resources.

A temporary closure should have no impacts on cultural resources as long as no additional lands are needed for the closure. A contingency plan for temporary cessation of operation would be implemented that would ensure compliance with all applicable LORS.

If a site were abandoned, impact to cultural resources would be unlikely because there would be no immediate soil disturbances. Over time, depending on the need to disturb the ground to accomplish project closure and facility removal, some disturbance of known and/or previously unknown cultural resources might result.

COMPLIANCE WITH APPLICABLE LORS

Riverside County and the City of Blythe have policies and goals for the protection of cultural resources, but have no specific procedures for implementation of CEQA that differ from procedures used by the Energy Commission. The property is within the incorporated boundaries of the City of Blythe. The General Plan requirements of the City are consistent with CEQA and the proposed Conditions of Certification. None of the resources identified are within designated districts for Riverside County. If there is work required by the City of Blythe that is outside of the incorporated boundaries, then the requirements of the County's General Plan would apply. Implementation of the mitigation measures recommended in the conditions of certification will ensure compliance with state and local LORS. Additional conditions may need to be added if there is work that is required that is outside of the City's incorporated boundaries.

Western is required to comply with federal regulations requiring them to take into account the impacts of their actions on cultural resources. Western would provide their interconnection agreement with conditions that would have to be fulfilled to reduce the impacts of the undertaking. Western does not have an active agreement with BEP II to conduct the work for the interconnection. At a minimum, Western will need a cultural resources assessment of the BEP II project and Interconnect area. Depending on the conclusions of the assessment, other information may be required If the point of interconnection changes to a facility that is not owned or controlled by Western and there are no other federal agencies involved, then federal requirements would not apply.

MITIGATION

For cultural resources, the preferred method of mitigation is for project construction to avoid areas where cultural resources are known to exist, wherever possible. Often however, avoidance cannot be achieved, and other measures such as surface collection, subsurface testing, and data recovery must be implemented for archaeological resources and documentation must be implemented for historical structures. Mitigation measures are developed to reduce the potential for adverse project impacts on cultural resources to a less than significant level, if possible.

APPLICANT'S PROPOSED MITIGATION

BEP II recommends that a Cultural Resources Specialist (CRS) would be retained and would be responsible for supervising all of the cultural resource mitigation procedures. The specialist would receive copies of maps and drawings to understand the areas where surface disturbance would take place. The CRS would be available if archeological materials are discovered during grading. The archeological material would be evaluated by the CRS and a mitigation plan would be implemented if the resource is evaluated as significant. The collected cultural materials would be recovered, analyzed, prepared for curation and delivered to a curation facility.

BEP II recommends a worker education program to ensure that buried archaeological resources are recognized by construction crews. Such a program would include information about the kinds of archaeological material that could be encountered, the procedures to be followed if such material is discovered, and the legal obligations and penalties. Any archaeological materials collected during the construction monitoring and mitigation program would be curated at a qualified curation facility.

The northern portion of CA-RIV-6370H on the project property would be fenced prior to any ground disturbing activities. Fence construction would be monitored by the CRS and the CRS would collect any cultural materials that are encountered. These materials would be added to the collection (BEP II 2002a, pp. 7.1-16, - 7.1-21). BEP II also agreed to accept a condition that would restrict all activities within the fenced area of CA-RIV-6370H. If BEP II proposed at a later time to use the fenced area, they would have to apply for an amendment (CEC 2003).

STAFF'S PROPOSED MITIGATION MEASURES

Commission staff concurs with the mitigation measures proposed by BEP II for cultural resources and agrees that these measures may reduce the impacts to resources to less than significant. However, additional mitigation measures for resources may be necessary. If the city requires ground disturbing activities outside of the plant site, then additional mitigation measures may be necessary. Staff's proposed conditions are consistent with applicants proposed measures. The Applicant's measures are incorporated into staff's proposed Conditions of Certification **CUL-1** through **CUL-8** presented below.

In summary, the conditions require implementation of the following measures. **CUL-1** requires that a qualified cultural resources specialist (CRS) manage cultural resources activities for the project. It also ensures that additional qualified specialists or cultural resources monitors would be retained as needed for the project. To ensure that cultural resources are adequately protected, **CUL-1** requires that the CRS have three years of experience in California. In addition to other relevant types of experience, the condition requires that the CRS have some background in data recovery.

CUL-2 requires the project owner to provide the CRS with the necessary maps and construction schedule information necessary to schedule monitors and cultural resources activity at the project site. The verification for the condition allows staff to verify that appropriate maps and construction schedule information have been provided to the CRS.

CUL-3 requires that a Cultural Resources Monitoring and Mitigation Plan (CRMMP) is developed that details all required activities that must be completed in order to reduce the impacts to a level that is less than significant. The CRMMP defines the roles and responsibilities of cultural resources personnel and provides timelines for the completion of the required mitigation. The CRS would also obtain Native American monitors to observe work in areas where Native American artifacts are found. The CRMMP requires a discussion of curation specifications, materials to be transferred to a curation facility, and the responsibility of the owner to pay all curation fees.

CUL-4 requires that the project owner provide a Cultural Resources Report (CRR) in Archaeological Resource Management Report (ARMR) format. This report would provide information on all field activities and the findings. The CRR would include all Department of Parks and Recreation (DPR) 523 forms and cultural resource reports not previously provided to the California Historic Resource Information System (CHRIS). Copies of the CRR would be provided to the State Historic Preservation Officer (SHPO), the CHRIS and the curating institution (if archaeological materials were collected).

CUL-5 provides for worker environmental training. The training serves to instruct workers that halting construction is necessary if a potential cultural resource is discovered. It also provides them with instruction regarding applicable laws, penalties and reporting requirements in the event something is discovered. Workers are also instructed that the CRS and other cultural resources personnel have the authority to halt construction in the event of a discovery.

CUL-6 requires monitoring of the ground disturbance for the project, linear facilities, and ancillary areas and a process for reducing monitoring to a level below full time. It also requires monitoring logs and weekly summaries of the monitoring activities. All non-compliance issues have to be reported to the CPM, and a reporting process is required. Any required Native American monitors should be obtained.

CUL-7 requires notification of staff within 24 hours of a cultural resources find. Timely notification enables staff participation in determinations of significance and the selection of appropriate mitigation to lessen impacts on cultural resources to a level that is less than significant.

It is not possible to determine whether previously undiscovered cultural resources may be potentially significant. It is necessary to discover the cultural resource and assess it in relation to a research design and the criteria that would make a resource eligible to the CRHR or NRHP. In addition, **CUL-6** ensures that unanticipated impacts to cultural resources are identified.

The CRS, alternate CRS and the CRMs have the authority to halt work so that the applicant has flexibility in construction scheduling. The CRS does not have to be at all active areas of construction at the same time. In order to ensure that an impact can be mitigated to less than significant, the individual on site needs to have the ability to stop construction when a discovery is made, not at a later point in time when the CRS has been contacted and informed about the discovery. This condition has been used with these provisions for over four years and has been effective in minimizing impacts to resources.

Cul-8 requires surveys and evaluations for portions of the project that are outside of the project site. If resources are determined to meet the eligibility requirements for the CRHR or the NRHP, then mitigation measures would be required.

An amendment to **Cul-9** would be required prior to (1) allowing any activities within the fenced portion of CA-RIV-6370H or removing of a portion of the fence. This condition would also bind any successor to to fulfil the requirements of the Memorandum of Agreement between Western and the CA SHPO.

CONCLUSIONS AND RECOMMENDATION

The City of Blythe has not concluded its planning process. The City may require ground disturbing activities outside of the project site. If ground disturbing activities are required outside of the project site, other resources could be identified or known resources could be impacted. Any newly identified resources would have to be evaluated to determine if it meets the eligibility requirements for the CRHR. Once the evaluation is completed, impacts and mitigation measures will be determined. The following is needed to complete the analysis, determine impacts, and necessary mitigation measures:

1. Staff has requested copies of the City's planning decision to determine whether ground disturbing activities will be required outside of the project area.
2. Staff is continuing consultation with Native American groups regarding resources that could be impacted by the project. If there is a resource that qualifies as a Native American sacred site, then mitigation measures would be developed to reduce the impacts to less than significant, if possible.
3. If ground disturbing activities will be required outside of the project area then a cultural resource survey of the area would need to be preformed, unless that area has been recently inventoried for cultural resources. If resources could be impacted by the activities, then the resources would have to be evaluated to determine if it meets the eligibility requirements for the CRHR and the NRHP. If a resource meets the eligibility requirements, then mitigation measures would be developed to reduce the impacts to less than significant.
4. The Applicant needs to negotiate a new agreement with Western to complete the federal analysis for the project.

PROPOSED CONDITIONS OF CERTIFICATION

CULTURAL RESOURCES STANDARD CONDITIONS

CUL-1 Prior to the start of ground disturbance, the project owner shall obtain the services of a **Cultural Resources Specialist (CRS)**, and one or more alternates, if alternates are needed, to manage all monitoring, mitigation and curation activities. The CRS may elect to obtain the services of **Cultural Resource Monitors (CRMs)** and other technical specialists, if needed, to assist in monitoring, mitigation and curation activities. The project owner shall ensure that the CRS evaluates any cultural resources that are newly discovered or that may be affected in an unanticipated manner for eligibility to the California Register of Historic Resources (CRHR). No ground disturbance shall occur prior to CPM approval of the CRS, unless specifically approved by the CPM.

CULTURAL RESOURCES SPECIALIST
The resume for the CRS and alternate(s) shall include information demonstrating that the minimum qualifications specified in the U.S. Secretary of Interior Guidelines, as published in the Code of Federal Regulations, 36 CFR Part 61 are met. In addition, the CRS shall have the following qualifications:

1. The technical specialty of the CRS shall be appropriate to the needs of the project and shall include a background in anthropology, archaeology, history, architectural history or a related field; and
2. At least three years of archaeological or historic, as appropriate, resource mitigation and field experience in California.

The resume of the CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS on referenced projects, and shall demonstrate that the CRS has the appropriate education and experience to accomplish the cultural resource tasks that must be addressed during ground disturbance, grading, construction and operation. In lieu of the above requirements, the resume shall demonstrate to the satisfaction of the CPM that the proposed CRS or alternate has the appropriate training and background to effectively implement the conditions of certification.

CULTURAL RESOURCES MONITOR

CRMs shall have the following qualifications:

1. a BS or BA degree in anthropology, archaeology, historic archaeology or a related field and one year experience monitoring in California; or
2. an AS or AA degree in anthropology, archaeology, historic archaeology or a related field and four years experience monitoring in California; or
3. enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historic archaeology or a related field and two years of monitoring experience in California.

CULTURAL RESOURCES TECHNICAL SPECIALISTS

The resume(s) of any additional technical specialists, e.g. historic archeologist, historian, architectural historian, physical anthropologist shall be submitted to the CPM for approval.

The project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval at least 45 days prior to the start of ground disturbance.

Verification: At least 10 days prior to a termination or release of the CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for review and approval.

At least 20 days prior to ground disturbance, the CRS shall provide a letter naming anticipated CRMs for the project and stating that the identified CRMs meet the minimum qualifications for cultural resource monitoring required by this condition. If additional CRMs are obtained during the project, the CRS shall provide additional letters to the CPM identifying the CRMs and attesting to the qualifications of the CRM, at least five days prior to the CRM beginning on-site duties. At least 10 days prior to beginning tasks, the resume(s) of any additional technical specialists shall be provided to the CPM for review and approval.

At least 10 days prior to the start of ground disturbance, the project owner shall confirm in writing to the CPM that the approved CRS will be available for on-site work and is prepared to implement the cultural resources conditions of certification.

CUL-2 Prior to the start of ground disturbance, the project owner shall provide the CRS and the CPM with maps and drawings showing the footprint of the power plant and all linear facilities. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:2000 or 1” = 200’) for plotting individual artifacts. If the CRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. The CPM shall review submittals and in consultation with the CRS approve those that are appropriate for use in cultural resources planning activities.

If construction of the project would proceed in phases, maps and drawings not previously provided shall be submitted prior to the start of each phase. Written notification identifying the proposed schedule of each project phase shall be provided to the CRS and CPM.

At a minimum, the CRS shall be consulted weekly by the project construction manager to confirm area(s) to be worked during the next week, until ground disturbance is completed.

The project owner shall notify the CRS and CPM of any changes to the scheduling of the construction phases. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless specifically approved by the CPM.

Verification: The project owner shall submit the subject maps and drawings at least 40 days prior to the start of ground disturbance. The CPM will review submittals in consultation with the CRS and approve maps and drawings suitable for cultural resources planning activities.

If there are changes to any project related footprint, revised maps and drawings shall be provided at least 15 days prior to start of ground disturbance for those changes.

If project construction is phased owner shall submit the subject maps and drawings, if not previously provided, 15 days prior to each phase.

A current schedule of anticipated project activity shall be provided to the CRS on a weekly basis during ground disturbance and also provided in each Monthly Compliance Report (MCR).

The project owner shall provide written notice of any changes to scheduling of construction phases within five days of identifying the changes.

CUL-3 Prior to the start of ground disturbance, the project owner shall submit the Cultural Resources Monitoring and Mitigation Plan (CRMMP), as prepared by the CRS, to the CPM for approval. The CRMMP shall identify general and specific measures to minimize potential impacts to sensitive cultural resources. Copies of the CRMMP shall reside with the CRS, alternate CRS, each monitor, and the project owner's on-site manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless specifically approved by the CPM.

The CRMMP shall include, but not be limited to, the following elements and measures.

1. A proposed general research design that includes a discussion of research questions and testable hypotheses applicable to the project area. A refined research design will be prepared for any resource where data recovery is required.
2. The following statement shall be added to the Introduction: Any discussion, summary, or paraphrasing of the conditions in this CRMMP is intended as general guidance and as an aid to the user in understanding the conditions and their implementation. If there appears to be a discrepancy between the conditions and the way in which they have been summarized, described, or interpreted in the CRMMP, the conditions, as written in the Final Decision, supercede any interpretation of the conditions in the CRMMP. (The Cultural Resources Conditions of Certification are attached as an appendix to this CRMMP.)
3. Specification of the implementation sequence and the estimated time frames needed to accomplish all project-related tasks during ground disturbance, construction, and post-construction analysis phases of the project.
4. Identification of the person(s) expected to perform each of the tasks, their responsibilities; and the reporting relationships between project construction management and the mitigation and monitoring team.
5. A discussion of the inclusion of Native American observers or monitors, the procedures to be used to select them, and their role and responsibilities.

6. A discussion of all avoidance measures (such as flagging or fencing), to prohibit or otherwise restrict access to sensitive resource areas that are to be avoided during construction and/or operation, and identification of areas where these measures are to be implemented. The discussion shall address how these measures would be implemented prior to the start of construction and how long they would be needed to protect the resources from project-related effects.
7. A discussion of the requirement that all cultural resources encountered shall be recorded on a DPR form 523 and mapped (may include photos). In addition, all archaeological materials collected as a result of the archaeological investigations (survey, testing, data recovery) shall be curated in accordance with The State Historical Resources Commission's "Guidelines for the Curation of Archaeological Collections," into a retrievable storage collection in a public repository or museum. The public repository or museum must meet the standards and requirements for the curation of cultural resources set forth at Title 36 of the Federal Code of Regulations, Part 79.
8. A discussion of any requirements, specifications, or funding needed for curation of the materials to be delivered for curation and how requirements, specifications and funding shall be met. If archaeological materials are to be curated, the name and phone number of the contact person at the institution. This shall include information indicating that the project owner will pay all curation fees and state that any agreements concerning curation will be retained and available for audit for the life of the project.
9. A discussion of the availability and the designated specialist's access to equipment and supplies necessary for site mapping, photographing, and recovering any cultural resource materials encountered during construction.
10. A discussion of the proposed Cultural Resource Report (CRR) which shall be prepared according to Archaeological Resource Management Report (ARMR) Guidelines.

<u>Verification:</u> The project owner shall submit the subject CRMMP at least 30 days prior to the start of ground disturbance. Per ARMR Guidelines the author's name shall appear on the title page of the CRMMP. Ground disturbance activities may not commence until the CRMMP is approved, unless specifically approved by the CPM. A letter shall be provided to the CPM indicating that the project owner would pay curation fees for any materials collected as a result of the archaeological investigations (survey, testing, data recovery).

CUL-4 The project owner shall submit the Cultural Resources Report (CRR) to the CPM for approval. The CRR shall be written by the CRS and shall be provided in the ARMR format. The CRR shall report on all field activities including dates, times and locations, findings, samplings and analysis. All survey reports, Department of Parks and Recreation (DPR) 523 forms and additional research reports not previously submitted to the California Historic Resource Information System (CHRIS) and the State Historic Preservation Officer (SHPO) shall be included as an appendix to the CRR.

Verification: The project owner shall submit the subject CRR within 90 days after completion of ground disturbance (including landscaping). Within 10 days after CPM approval, the project owner shall provide documentation to the CPM that copies of the CRR have been provided to the SHPO, the CHRIS and the curating institution (if archaeological materials were collected).

CUL-5 Prior to and for the duration of ground disturbance, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment. The training may be presented in the form of a video. The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Samples or visuals of artifacts that might be found in the project vicinity;
3. Information that the CRS, alternate CRS, and CRMs have the authority to halt construction to the degree necessary, as determined by the CRS, in the event of a discovery or unanticipated impact to a cultural resource;
4. Instruction that employees are to halt work on their own in the vicinity of a potential cultural resources discovery, and shall contact their supervisor and the CRS or CRM; and that redirection of work would be determined by the construction supervisor and the CRS;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. An acknowledgement form signed by each worker indicating that they have received the training; and
7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

No ground disturbance shall occur prior to implementation of the WEAP program, unless specifically approved by the CPM.

Verification: The project owner shall provide in the Monthly Compliance Report the WEAP Certification of Completion form of persons who have completed the training in the prior month and a running total of all persons who have completed training to date.

CUL-6 The project owner shall ensure that the CRS, alternate CRS, or CRMs shall monitor ground disturbance full time in the vicinity of the project site, linears and ground disturbance at laydown areas or other ancillary areas to ensure there are no impacts to undiscovered resources and to ensure that known resources are not impacted in an unanticipated manner. In the event that the CRS determines that full-time monitoring is not necessary in certain locations, a letter or e-mail providing a detailed justification for the decision to reduce the level of monitoring shall be provided to the CPM for review and approval prior to any reduction in monitoring.

CRMs shall keep a daily log of any monitoring or cultural resource activities and the CRS shall prepare a weekly summary report on the progress or status of cultural resources-related activities. The CRS may informally discuss cultural resource monitoring and mitigation activities with Energy Commission technical staff.

The CRS and the project owner shall notify the CPM by telephone or e-mail of any incidents of non-compliance with the conditions of certification and/or applicable LORS upon becoming aware of the situation. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the conditions of certification.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these conditions of certification.

A Native American monitor shall be obtained to monitor ground disturbance in areas where Native American artifacts may be discovered. Informational lists of concerned Native Americans and Guidelines for monitoring shall be obtained from the Native American Heritage Commission. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that shall be monitored.

Verification: During the ground disturbance phases of the project, if the CRS wishes to reduce the level of monitoring occurring at the project, a letter or e-mail identifying the area(s) where the CRS recommends the reduction and justifying the reductions in monitoring shall be submitted to the CPM for review and approval. Documentation justifying a reduced level of monitoring shall be submitted to the CPM at least 24 hours prior to the date of planned reduction in monitoring.

During the ground disturbance phases of the project, the project owner shall include in the MCR to the CPM copies of the weekly summary reports prepared by the CRS regarding project-related cultural resources monitoring. Copies of daily logs shall be retained and made available for audit by the CPM.

Within 24 hours of recognition of a non-compliance issue with the conditions of certification and/or applicable LORS, the CRS and the project owner shall notify the CPM by telephone of the problem and of steps being taken to resolve the problem. The telephone call shall be followed by an e-mail or fax detailing the non-compliance issue and the measures necessary to achieve resolution of the issue. Daily logs shall include forms detailing any instances of non-compliance. In the event of any non-compliance issue, a report written no sooner than two weeks after resolution of the issue that describes the issue, resolution of the issue and the effectiveness or the resolution measures, shall be provided in the next MCR.

One week prior to ground disturbance in areas where there is a potential to discover Native American artifacts, the project owner shall send notification to the CPM identifying the person(s) retained to conduct Native American monitoring. The project owner shall also provide a plan identifying the proposed monitoring schedule and information explaining how Native Americans who wish to provide comments will be allowed to comment. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM. The

CPM will either identify potential monitors or will allow ground disturbance to proceed without a Native American monitor.

CUL-7 The project owner shall grant authority to halt construction to the CRS, alternate CRS and the CRMs in the event previously unknown cultural resource sites or materials are encountered, or if known resources may be impacted in a previously unanticipated manner (discovery). Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event cultural resources are found or impacts can be anticipated, the halting or redirection of construction shall remain in effect until all of the following have occurred:

1. The CRS has notified the project owner, and the CPM has been notified within 24 hours of the discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning, including a description of the discovery (or changes in character or attributes), the action taken (i.e. work stoppage or redirection), a recommendation of eligibility and recommendations for mitigation of any cultural resources discoveries whether or not a determination of significance has been made.
2. The CRS, the project owner, and the CPM have conferred and determined what, if any, data recovery or other mitigation is needed; and
3. Any necessary data recovery and mitigation has been completed.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM and CRS with a letter confirming that the CRS, alternate CRS and CRMs have the authority to halt construction activities in the vicinity of a cultural resource discovery, and that the project owner shall ensure that the CRS notifies the CPM within 24 hours of a discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning.

CUL-8 Prior to any project-related activities, such as transmission line reconductoring, pole replacement, or any other project-related task which may result in ground disturbance that was not included in information provided to the Energy Commission, the project owner must determine the availability of current (i.e. within 5 years) cultural resource surveys of the proposed ground disturbance. If there are not current surveys, the project owner must ensure that new surveys are preformed. If cultural resources are identified that cannot be avoided, they must be evaluated for eligibility for the National Register of Historic Places and the CRHR.

The responsibility for the evaluation must be taken by persons meeting the Secretary of the Interior's Professional Qualification Standards in a discipline appropriate to the historic context within which the resource is being considered (OHP 1995). If significant cultural resources would be affected, then mitigation measures shall be determined in consultation with the CPM and Western.

Verification: At least 30 days prior to ground disturbance associated with project-related activities not previously described in the AFC or other information provided to the Energy Commission, the project owner shall provide the results of any additional cultural resource surveys and evaluations in the form of a technical report (with request for confidentiality, if needed), along with any associated maps, to the CPM for review and approval. All required mitigation shall be completed prior to construction of the project-related activities.

Cul-9 The project owner or its agents shall not conduct any activities within the fenced portion of CA-RIV-6370H or remove any portion of the fence without approval of the CPM. Any contract or agreement to purchase any interest in the project (or land identified in the AFC as the project area) must include a clause obligating the successor in interest to the terms of the Memorandum of Agreement between Western and the CA SHPO.

Verification: The project owner shall make a statement in each Monthly Compliance Report during construction and in each Annual Compliance Report during operation regarding compliance with this condition.

REFERENCES

Caithness Blythe II, LLC/Looper (tn: 26100). Revised Application for Certification for Blythe II. Submitted to CEC/Larson/Dockets on 7/03/2002.
Cited as BEP II 2002a.

CEC. Final Staff Assessment and Environmental Assessment on Blythe Energy Project filed jointly by Energy Commission staff and Western Area Power Administration, November 13, 2000.
Cited as CEC 2000

CEC. Final Commission Decision on the Blythe Power Plant Project. Posted on CEC web page: March 26, 2001.
Cited as CEC 2001a

CEC. Staff analysis of the proposed amendment to place earth fill from the Blythe Energy Project (99-AFC-8C). Posted on CEC web page July 1, 2001.
Cited as CEC 2001b

CEC/Reinoehl (tn: 28577). Report of Conversation with Tom Cameron, Bob Looper, Scott Galati & Peter Boucher re: Data Response Workshop. Submitted to CEC/Dockets on 4/26/2003.
Cited as CEC 2003.

Native American Heritage Commission/Wood (tn: 26613). Native American contact for proposed new power plant in Riverside County in the City of Blythe. Submitted to CEC/Reinoehl/Dockets on 9/06/2002.
Cited as NAHC 2002.

HAZARDOUS MATERIALS MANAGEMENT

Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

The purpose of this Hazardous Materials Management analysis is to determine if the proposed Blythe Energy Project Phase II (BEP II) has the potential to cause significant impact on the public as a result of the use, handling or storage of hazardous materials at the proposed facility. If significant adverse impacts on the public are identified, Energy Commission staff must also evaluate the potential for facility design alternatives and additional mitigation measures to reduce impacts to the extent feasible.

This analysis does not address potential exposure of workers to hazardous materials used at the proposed facility. Employers must inform employees of hazards associated with their work and provide employees with special protective equipment and training to reduce the potential for health impacts associated with the handling of hazardous materials. The **Worker Safety and Fire Protection** section of this document describes the requirements applicable to the protection of workers from such risks.

Aqueous ammonia (19.5 to 30 percent ammonia in aqueous solution) and anhydrous ammonia are the only acutely hazardous material proposed to be used or stored at the BEP II in quantities exceeding the reportable amounts defined in the California Health and Safety Code, section 25532 (j) (BEP II 2003f, Table 7.9-2). Aqueous ammonia would be used for controlling oxides of nitrogen (NO_x) emissions through selective catalytic reduction and for condensate pH control. Anhydrous ammonia may be used in the inlet chilling system.

BEP II has proposed to use either anhydrous ammonia or a hydrochlorofluorocarbon (HCFC) such as R-123 as a refrigerant for an inlet chilling system. This system would use either approximately 17,400 pounds of anhydrous ammonia or approximately 22,000 pounds of R-123, both circulating in a closed loop system. The use of a closed system would avoid refrigerant exposure to atmospheric conditions and would obviate the need for routine deliveries of either refrigerant because losses would be minimal (BEP II 2003f). Anhydrous ammonia is stored as a liquefied gas at elevated pressure and high internal energy that can act as a driving force in an accidental release thus rapidly introducing large quantities of the material to the ambient air and resulting in high down-wind concentrations. R-123 is classified as a Class II Ozone Depleting Substance in Section 602 of the Clean Air Act. Because of this ozone depleting potential, production of R-123 will be prohibited in 2020 in developed countries and 2030 in developing countries. The applicant stated that R-123 unavailability will be a consideration when selecting the refrigerant for the inlet air cooling system (BEP II 2003f, Page 2-2).

Other hazardous materials, such as mineral and lubricating oils, corrosion inhibitors and water conditioners, will be present at the proposed facility. Hazardous materials used during the construction phase include gasoline, diesel fuel, oil, welding gases, lubricants, solvents and paint. No acutely toxic hazardous materials will be used onsite during construction. None of these materials pose significant potential for off-site impacts as a result of the quantities on-site, their relative toxicity, their physical state, and/or their environmental mobility. Although no natural gas is stored, the project will also involve the handling of large amounts of natural gas. Natural gas poses some risk of fire. BEP II will tap into the natural gas line constructed for the approved BEP I and therefore would not require the construction of a new gas pipeline (BEP II 2002d Section 2.2.7). This line supplies natural gas from the El Paso Natural Gas Terminal on the Arizona side of the Colorado River.

The BEP II will also require the transportation of aqueous ammonia to the facility. Analysis of the potential for impact associated with such deliveries is addressed below.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies apply to the protection of public health and hazardous materials management. Staff's analysis examines the project's compliance with these requirements.

FEDERAL

The Superfund Amendments and Reauthorization Act of 1986 (42 USC §9601 et seq.), contains the Emergency Planning and Community Right To Know Act (also known as SARA Title III). The Clean Air Act (CAA) of 1990 (42 USC 7401 et seq. as amended) established a nationwide emergency planning and response program and imposed reporting requirements for businesses which store, handle, or produce significant quantities of extremely hazardous materials. The CAA section on Risk Management Plans (42 USC §112(r)) requires the states to implement a comprehensive system to inform local agencies and the public when a significant quantity of such materials is stored or handled at a facility. The requirements of both SARA Title III and the CAA are reflected in the California Health and Safety Code, section 25531, et seq. Suppliers of hazardous materials must adhere to the U.S. Department of Transportation (DOT) requirements for Hazardous Materials vendors to prepare and implement security plans as per 49 CFR 172.800 and to ensure that all their hazardous materials drivers are in compliance with personnel background security checks as per 49 CFR Part 1572, Subparts A and B.

STATE

The California Health and Safety Code, section 25534, directs facility owners, storing or handling acutely hazardous materials in reportable quantities, to develop a Risk Management Plan (RMP) and submit it to appropriate local authorities, the United States Environmental Protection Agency (EPA), and the designated local administering agency for review and approval. The plan must include an evaluation of the potential impacts associated with an accidental release, the likelihood of an accidental release occurring, the magnitude of potential human exposure, any preexisting evaluations or studies of the material, the likelihood of the substance being handled in the manner indicated, and the accident history of the material. This new, recently developed program supersedes the California Risk Management and Prevention Plan (RMPP).

Title 8, California Code of Regulations, Section 5189, requires facility owners to develop and implement effective safety management plans to insure that large quantities of hazardous materials are handled safely. While such requirements primarily provide for the protection of workers, they also indirectly improve public safety and are coordinated with the RMP process.

Title 8, California Code of Regulations, Section 458 and Sections 500 to 515, set forth requirements for design, construction and operation of vessels and equipment used to store and transfer ammonia. These sections generally codify the requirements of several industry codes, including the American Society for Material Engineering (ASME) Pressure Vessel Code, the American National Standards Institute (ANSI) K61.1 and the National Boiler and Pressure Vessel Inspection Code. These codes apply to anhydrous ammonia but are also used to design storage facilities for aqueous ammonia.

California Health and Safety Code, section 41700, requires that “No person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property.

LOCAL

The Uniform Fire Code (UFC) contains provisions regarding the storage and handling of hazardous materials in Articles 79 and 80. The latest revision to Article 80 was published in 1997 (Uniform Fire Code, 1997) and includes minimum setback requirements for outdoor storage of ammonia. The administering agency for this authority is the City of Blythe.

The Certified Unified Program Authority (CUPA) with responsibility to review RMPs and Hazardous Materials Business Plans is the Riverside County Hazardous Materials Division.

SETTING

The proposed BEP II would be located on the western portion of a 152-acre parcel of land, which includes the approved BEP I site. This site is located east of the Blythe Airport, approximately 5 miles west of the center of the City of Blythe, bordering Hobsonway on the south and Buck Boulevard on the east. Buck Boulevard was paved as part of the approved BEP, and would be the main access to the site. The site topography is flat, with an elevation of 390 feet above mean sea level. The nearest residence is approximately 2,750 feet southwest of the site. The closest schools are located approximately 4.5 miles east of the proposed BEP II site, in the City of Blythe.

The proposed project will be a combined-cycle electric generating facility consisting of two Siemens Westinghouse V84.3a F-Class combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and a steam turbine generator (STG), along with accompanying auxiliary systems and equipment. Natural gas-fuel will be supplied by the pipeline constructed as part of the approved BEP I.

Several factors associated with the area in which a project is to be located affect its potential to cause public health impacts from an accidental release of a hazardous material. These include:

- local meteorology;
- terrain characteristics; and
- location of population centers and sensitive receptors relative to the project.

METEOROLOGICAL CONDITIONS

Meteorological conditions, including wind speed, wind direction and air temperature, affect the extent to which accidentally released hazardous materials would be dispersed into the air and the direction in which they would be transported. This affects the potential magnitude and extent of public exposure to such materials, as well as the associated health risks. When wind speeds are low and the atmosphere is stable, dispersion is severely reduced and can lead to increased localized public exposure.

Recorded wind speeds and ambient air temperatures are described in the Air Quality section (7.7) and Appendix 7.9 of the AFC (BEP II 2002d). Staff agrees with the applicant that use of F stability (stagnated air, very little mixing) and 1.0 meter per second wind speed is appropriate for conducting the Offsite Consequence Analysis. Staff believes these represent a reasonably conservative scenario and thus reflects worst case atmospheric conditions.

TERRAIN CHARACTERISTICS

The location of elevated terrain (terrain above the power plant stack height) is often an important factor to be considered in assessing potential exposure. An emission plume resulting from an accidental release may impact high elevations before impacting lower elevations. The BEP site is approximately 70 feet above and west of the Colorado River Valley and the City of Blythe, and about 60 feet below the elevation and east of the Blythe Airport. Terrain above the stack height (130 feet) within a 10-mile radius exists approximately 4 miles to the east of the proposed site (BEP II 2002d Figure 7.8-1).

LOCATION OF EXPOSED POPULATIONS AND SENSITIVE RECEPTORS

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a large bearing on health risk. Figure 7.9-1 in the AFC (BEP II 2002d) shows the location of sensitive receptors in the project vicinity. The nearest sensitive receptors are approximately 4.5 miles away in the City of Blythe.

IMPACTS AND ANALYSIS

Staff reviewed and assessed the potential for the transportation, handling, and use of hazardous materials to impact the surrounding community. All chemicals and natural gas were evaluated.

METHODOLOGY

In order to assess the potential for released hazardous materials to travel off-site and affect the public, staff analyzed several aspects of the proposed use of these materials at the facility. Staff recognizes that some hazardous materials must be used at power plants. Therefore, staff conducted its analysis by examining the choice and amount of chemicals to be used, the manner in which the applicant will use the chemicals, the manner it will be transported to the facility and transferred to facility storage tanks, and the way the applicant plans to store the materials on-site.

Staff reviewed the applicant's proposed engineering controls and administrative controls concerning hazardous materials usage. Engineering controls are those physical or mechanical systems, such as storage tanks or automatic shut-off valves, that can prevent a spill of hazardous material from occurring or which can limit the spill to a small amount or confine it to a small area. Administrative controls are those rules and procedures that workers at the facility must follow that will help to prevent accidents or keep them small if they do occur. Both engineering and administrative controls can act as methods of prevention or as methods of response and minimization. In both cases, the goal is to prevent a spill from moving off-site and causing harm to the public.

Staff reviewed and evaluated the applicant's proposed use of hazardous materials as described by the applicant (BEP II 2003f, AFC Section 7.9). Staff's assessment followed the five steps listed below:

- Step 1: Staff reviewed the chemicals and the amounts proposed for on-site use as listed in Table 7.9-2 of the Supplement to Revision I of the AFC and determined the need and appropriateness of their use.
- Step 2: Those chemicals, proposed for use in small amounts or whose physical state is such that there is virtually no chance that a spill would migrate off the site and impact the public, were removed from further assessment.
- Step 3: Measures proposed by the applicant to prevent spills were reviewed and evaluated. These included engineering controls such as automatic shut-off valves and different size transfer-hose couplings and administrative controls such as worker training and safety management programs.
- Step 4: Measures proposed by the applicant to respond to accidents were reviewed and evaluated. These measures also included engineering controls such as catchment basins and methods to keep vapors from spreading and administrative controls such as training emergency response crews.
- Step 5: Staff analyzed the theoretical impacts on the public of a worst-case spill of hazardous materials even with the mitigation measures proposed by the applicant. When mitigation methods proposed by the applicant are sufficient, no further mitigation is recommended. If the proposed mitigation is not sufficient to reduce the

potential for adverse impacts to an insignificant level, staff will propose additional prevention and response controls until the potential for causing harm to the public is reduced to an insignificant level. It is only at this point that staff can recommend that the facility be allowed to use hazardous materials.

PROJECT IMPACTS

Small Quantity Hazardous Materials

In conducting the analysis, staff determined in Steps 1 and 2 that some materials, although present at the proposed facility, pose a minimal potential for off-site impacts as they will be stored in a solid form or in smaller quantities, have low mobility, or have low levels of toxicity. These hazardous materials, which were eliminated from further consideration, are discussed briefly below.

During the construction phase of the project, the only hazardous materials proposed for use include paint, paint thinner, cleaners, solvents, sealants, gasoline, diesel fuel, motor oil, hydraulic fluid, lubricants, welding flux and compressed gases. In addition to these materials, hydroxyacetic acid (approximately 1,000 pounds) and formic acid (approximately 600 pounds) will be used by a contractor to clean the Heat Recovery Steam Generators feedwater system prior to start up. Any impact of spills or other releases of these materials will be limited to the site due to the small quantities involved, the infrequent use and hence reduced chances of release, and/or the temporary containment berms used by contractors. Petroleum hydrocarbon-based motor fuels, mineral oil, lube oil, and diesel fuel are all of very low volatility and represent limited off-site hazard even in larger quantities.

During operations, acutely hazardous chemicals such as cyclohexylamine, morpholine, ethanolamine, methoxypropylamine, and other various chemicals (see Appendix C of this document for a list of all chemicals proposed to be used and stored at BEP II), would be used and stored in relatively small amounts and represent limited off-site hazard due to their small quantities, low volatility, and/or low toxicity.

After removing from consideration those chemicals that pose no risk of off-site impact in Steps 1 and 2, staff continued with Steps 3, 4, and 5 to review the remaining hazardous materials: sodium hypochlorite, sodium hydroxide, hydrochloric acid, sulfuric acid, natural gas, aqueous ammonia, anhydrous ammonia, and R-123.

Large Quantity Hazardous Materials

Sodium hypochlorite, sodium hydroxide, and sulfuric acid will be stored on-site but do not pose a risk of off-site impacts because they have relatively low vapor pressures and thus spills would be confined to the site. Because of concern at another proposed energy facility in 1995, staff conducted a quantitative assessment of the potential for impact associated with sulfuric acid use, storage, and transportation. Staff found no hazard would be posed to the public due to the extremely low volatility of this aqueous solution of sulfuric acid. However, in order to protect against risk of fire, staff proposes Condition of Certification **HAZ-5** which will require that no combustible or flammable material is stored within 50 feet of the sulfuric acid tank.

Anhydrous Ammonia

Anhydrous ammonia is being considered by the Applicant to be used as a refrigerant in the inlet air chiller system. The use of anhydrous ammonia can result in the formation and release of a gaseous cloud in the event of a release, even without interaction with other chemicals. This is a result of its relatively high vapor pressure and the large amounts of anhydrous ammonia that will be used in the closed loop cooling system. Anhydrous ammonia is a gas at ambient temperature but in many parts of the refrigerating system would exist as a liquid under high pressure. The rupture of a pipe or valve in the chilling system would likely result in a release of a mixture of ammonia vapor and very fine liquid droplets. The result of such a release would be a denser-than-air mixture that would create a vapor cloud. If a release occurred in other parts of the refrigerating system where ammonia is in the pure vapor phase, the ammonia would be less dense than air, would release at a faster rate, and would not form a vapor cloud.

The anhydrous ammonia will be kept in a closed loop system that will have no contact with the outside atmosphere. Piping of the chilling system will be welded construction with minimal flanged connections to minimize the potential for spills. Safety controls such as ammonia detection equipment, alarms and an automatic shutdown system would be installed in the equipment enclosures. Additionally, an automatic fire suppression system would be installed to minimize the chances that a fire may cause an accidental release from the system (BEP II 2003f Page 7.9-29). The refrigeration system would not require routine deliveries of anhydrous ammonia, but may require small quantities from time to time to keep the system charged (BEP 2003a, Page 78). According to the applicant, this occasional recharge would require only approximately 300 pounds of additional refrigerant every four to five years, delivered by tanker truck with varying degrees of load as part of routine deliveries to other recipients (Gavahan 2003). Additionally, it may be necessary to drain and recharge the entire system during the life of the plant.

The Supplement to Revision 1 of the AFC (BEP 2003b, section 7.9) discusses the modeling parameters for a worst case and alternative case accidental release of anhydrous ammonia. The worst-case release in the AFC is associated with a failure at the location of the high pressure receiver where all 17,400 pounds could be emitted. The rate of release through an assumed hole of ½ inch in diameter was calculated using the Bernoulli's Formula to be 3.13 kg/sec and 1.74 kg/sec for the high and low pressure of the system respectively. The U.S. EPA DEGADIS air dispersion model was used to estimate airborne concentrations of ammonia. Two atmospheric conditions were used to model the worst-case scenario under high and low pressure: stability class F with wind speed of 1 m/s, and stability class D with wind speed of 3 m/s.

The results of the low pressure modeling (60 psig) with stability class F predicted concentration of 100 ppm at 2.4 miles from the source. Concentrations of greater than 1000 ppm were predicted out to a distance of 0.3 miles from the source. For stability class D this scenario predicted concentrations greater than 1000 ppm out to 0.1 mile from the source, and 100 ppm at 0.53 miles. The results of the high pressure modeling (195 psig) with stability class F predicted concentration of 100 ppm at 2.9 miles from the source, and concentrations greater than 1000 out to 0.2 miles. For stability class D this scenario predicted concentrations greater than 1000 ppm out to 0.11 miles from the source, and 100 ppm at 0.66 miles from the facility.

According to the AFC, the nearest residence to the BEP II facility is approximately 0.75 miles southwest. The community of Mesa Verde (Nicholls Warm Springs) is about 2.2 miles southwest of the anhydrous ammonia refrigerating system. About 5 to 6 isolated residences are also located on the elevated Palo Verde Mesa near the BEP II site (BEP II 2003f Page 7.9-26). According to the modeling results for worst-case scenario with stability class F, the nearest residence may experience ammonia concentrations slightly over 400 ppm while the surrounding population could be impacted by concentrations greater than 100 ppm. With stability class D, an ammonia concentration of approximately 100 ppm is estimated to occur at the nearest residence.

To assess the potential impacts associated with an accidental release of either anhydrous or aqueous ammonia, staff typically evaluates where four “bench mark” exposure levels of ammonia gas occur off-site. These include:

1. the lowest concentration posing a risk of lethality, 2,000 ppm;
2. the Immediately Dangerous to Life and Health (IDLH) level of 300 ppm;
3. the Emergency Response Planning Guideline Level 2 (ERPG-2) of 150 ppm, which is also the RMP Level 1 criterion used by EPA and California; and
4. the level considered by the Energy Commission staff to be without serious adverse effects on the public for a one-time exposure: 75 ppm.

Because members of the off-site public would be exposed to airborne concentrations considerably in excess of staff’s 75 ppm, and some off-site public would even experience airborne concentrations in excess of the ERPG-2 and the IDLH level, staff found it necessary to conduct further review and evaluation of this option for the inlet chiller. To do this, staff reviewed the accident frequency for releases from ammonia refrigeration units. This review also included an assessment staff conducted for the BEP I facility as found in the Final Staff Assessment for that project. For that project, staff had requested that the applicant provide an analysis of the potential for a release of anhydrous ammonia from the refrigeration unit. The applicant provided results which indicated a probability of accidental release ranging between 7.2 in 10,000 and 3.6 in 100,000 plant years of operation. Further evaluation by staff indicated that serious releases involving refrigeration plants occur at a frequency of about 1 in 100,000 per plant year of operation (Baldcock, 1980).

Staff also evaluated the potential for impacts on three specific receptor locations including Nicholls Warm Springs, the Blythe Airport and on Interstate 10. The modeling results indicate that significant impacts would occur at Nicholls Warm Springs, about 2 miles from the project, with winds from the east and north east direction with E or F stability. Staff’s analysis indicates that winds in the direction of Nicholls Warm Springs with E or F stability occur with a frequency of about 0.021 (about two percent of the time)(BEP, 1999a). Thus, significant impacts on Nicholls Warm Springs would have a probability of occurrence of about 2 in 10,000,000 per year. Staff’s analysis of the Blythe Airport, about 1.5 miles from the project, indicates the probability of impact with winds from the south east and with D, E and F stability. These meteorological conditions occur with a frequency of about 0.011 (about one percent of the time). Thus, the risk of significant impact at the Blythe Airport is about 1 in 10,000,000. The modeling results indicate that impacts on Interstate 10, about 0.25 miles from the project, could be associated with winds from the north, north by north east, north east, east by north east, west by north west, north west and north by north west with D, E or F stability. These meteorological conditions occur with a frequency of about 0.203 (about 20 percent of the time). Thus, the risk of significant impact on Interstate 10 is about 2 in 1,000,000. In general, staff considers a risk above 1 in 1,000,000 per year significant with the potential of more than 100 serious injuries and or fatalities. Staff could not quantify the potential number of injuries or fatalities that could result from a release affecting Interstate 10. However, staff does believe that such an event has the potential to cause more than 100 injuries and or fatalities on Interstate 10. While this level of risk cannot be considered insignificant, it is close to an insignificant level of risk. It is typical regulatory practice in such cases to impose mitigation to reduce risk to the lowest level that is reasonably practical.

After review of the accident release data and frequency of occurrence at ammonia refrigeration units, staff has concluded that the accident release frequency and the resultant impacts can be significant. Indeed, the U.S. EPA issued a Safety Alert on Ammonia Used as a Refrigerant in 1998 (EPA 1998) and published a Chemical Safety Alert on ammonia releases from refrigeration facilities in 2001 (EPA 2001). This document also recommends the adoption and implementation of a hazard reduction plan at facilities that use anhydrous ammonia for refrigeration. Staff finds that although the chances of accidental release from the proposed BEP II would be small, the impacts of such a release could be quite significant. Therefore, in order to reduce this risk to a level of insignificance, staff proposes Condition of Certification (**HAZ-8**) which would require the Applicant to prepare and implement an Ammonia Refrigeration Hazard Reduction Plan consistent with U.S. EA guidelines (EPA 2001). Additionally, technical organizations such as the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE), the International Institute of Ammonia Refrigeration (IIAR), and the American National Standards Institute (ANSI), have established codes, standards, and guidelines for the safe use of anhydrous ammonia as a refrigerant. The proposed refrigeration plant will also be subject to regulations requiring participation in the State Risk Management Program (RMP) and Process Safety Management (PSM) program post certification. It is staff's opinion that participation in these programs will result in development and implementation of extensive administrative controls designed to improve the safety of the plant. Staff is also proposing the use of an automatic fire suppression system similar to that required for the BEP I project. Requiring the use of an automatic fire suppression system is supported by the record of past releases from refrigeration plants that suggests a significant causal relationship between fires and accidental releases from such plants. Staff is proposing a condition of certification (**HAZ-10**) requiring installation of an automatic fire suppression system on the refrigeration plant.

Based on the analysis above, staff concludes that the risk associated with the proposed use of anhydrous ammonia as refrigerant are below significant levels if the mitigation measures described above are required.

Aqueous Ammonia

Aqueous ammonia will be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The accidental release of aqueous ammonia without proper mitigation can result in very high down-wind concentrations of ammonia gas. Two storage tanks will be used to store the 19 to 30 percent aqueous ammonia with a maximum capacity of 10,000 gallons each.
The use of aqueous ammonia can result in the formation and release of toxic gases in the event of a spill even without interaction with other chemicals. This is a result of its moderate vapor pressure and the large amounts of aqueous ammonia that will be used and stored on-site. However, as with sodium hypochlorite solution, the use of aqueous ammonia instead of the much more hazardous anhydrous ammonia (i.e. ammonia that is not diluted with water) poses far less risk.

To assess the potential impacts associated with an accidental release of aqueous ammonia, staff uses the four "bench mark" exposure levels of ammonia gas described above for anhydrous ammonia. (A detailed discussion of the exposure criteria considered by staff and their applicability to different populations and exposure-specific conditions is provided in Appendix A of this analysis.) If the potential exposure associated with a potential release exceeds 75 ppm at any public receptor, staff presumes that the potential release poses a risk of significant impact. However, staff also assesses the probability of occurrence of the release and/or the nature of the potentially exposed population in determining whether the likelihood and extent of potential exposure is sufficient to support a finding of potentially significant impact.

Section 7.9.2.2.1 of the AFC (BEP II 2002d) describes the modeling parameters used for the worst case accidental releases of aqueous ammonia in the applicant's Off-site Consequence Analysis (OCA). According to the applicant, the worst-case release is associated with a failure of one of the storage tanks into the containment area, and the second scenario is associated with a spill from a delivery tanker truck during loading operation. The ALOHA program air dispersion model was used for modeling the aqueous ammonia releases. The ALOHA program cannot directly model solutions (like ammonia in water), and assumes that the entire content of an aqueous ammonia release is anhydrous ammonia. Therefore the ALOHA program would significantly over predict the threat zone of an aqueous ammonia release.

The worst-case storage tank spill (scenario #1) assumed a release of aqueous ammonia in a rate of 0.127 kg/s, winds of 1.0 meter per second, ambient temperature of 100°F, and category F stability. The second storage tank spill (scenario #2) used stability class D, a wind speed of 5.0 m/s, and ambient temperature of 100°F. The ammonia delivery truck spill (scenario #3) assumed the tanker would contain 5,000 gallons of aqueous ammonia, the release would last only three to five minutes before being controlled, would be totally contained in a diked area around the loading area, and that the meteorological conditions were winds of 1.0 m/s, ambient temperature of 100°F, and stability class F (BEP II 2002d, AFC Page 7.9-19). The spill rate was calculated to be 3.17 kg/s using the NOAA methodology. The final delivery truck spill (scenario #4) assumed winds of 5.0 m/s, ambient temperature of 100°F, and stability class D.

The results of the applicant's modeling showed that off-site airborne concentrations of ammonia would exceed the level staff uses to establish insignificance (75 ppm) out to a distance of 0.86 miles from the ammonia storage tank for the tank spill scenario modeled with F stability. The maximum concentration at the nearest site boundary (Hobsonway- approximately 0.15 miles or 800 feet south from the tank according to the AFC) was calculated to be approximately 2,000 ppm. For the tank spill scenario modeled with stability class D, results showed a concentration of 75 ppm at 0.24 miles from the ammonia storage tank and approximately 200 ppm at the nearest site boundary (BEP II 2002d, AFC Pages 7.9-18 and 7.9-19 and Figures 7.9-2 and 7.9-3).

For the second scenario involving a spill from a delivery truck, the applicant's modeling using stability class F showed a concentration of 75 ppm at 6.0 miles away from the truck unloading area. Over 2,000 ppm was calculated at the nearest site boundary. The modeling using stability class D showed a concentration of 75 ppm at 1.7 miles, and over 2,000 ppm at the nearest site boundary (BEP II 2002d, AFC Page 7.9-19 and Figures 7.9-4 and 7.9-5).

Staff has reviewed this Off-site Consequence Analysis and found the results to be indicative of significant off-site impacts. Because the applicant used an air dispersion model which significantly over-predicts downwind airborne concentrations, staff conducted SCREEN 3 modeling for two different scenarios associated with a failure of the aqueous ammonia storage tank. Staff assessed the potential for impact from a spill into the secondary containment depicted in Figure 2.0-4 of the AFC. Staff estimated the surface area of the containment area at 1,144 square feet. The applicant is not proposing to install a subsurface sump under the storage tank or under the tanker truck transfer area. Staff evaluated the airborne dispersion of ammonia vapors if the spill occurred at temperatures of 120°F. The US EPA SCREEN3 model was run for rural terrain, and for atmospheric stability class F with a wind speed of 1.0 m/s and for atmospheric stability class D with a wind speed of 5 m/s. Staff also recalculated the distances from the aqueous ammonia storage tank to the nearest fenceline (695 feet) and the nearest residence (3628 feet) using AFC Figures 2.0-4 and 7.9-6. Staff also modeled a spill during transfer from a tanker truck to the storage tank using the same two meteorological scenarios and a spill area of 266 square feet.

The results of staff's modeling show that if an accidental release of aqueous ammonia from the storage tank occurs, airborne concentrations of ammonia are predicted to be 2,558 ppm at the fenceline and 170 ppm at the nearest residence for the worst-case spill (F stability with 1 m/s wind speed). For the other more likely meteorological scenario (D stability with 5 m/s wind speed), the airborne concentrations of ammonia are predicted to be 447 ppm at the fenceline and 26 ppm at the nearest residence. Staff's modeling also found that for a transfer spill, the airborne concentration of ammonia is predicted to be 1,565 at the fenceline and 105 ppm at the nearest residence for the worst-case spill (F stability with 1 m/s wind speed) and 275 ppm at the fenceline and 16 ppm at the nearest residence (D stability with 5 m/s wind speed). The predicted levels of 26 ppm and 16 ppm at the nearest residence for the more likely meteorological scenario do not represent a significant risk to the public.
Therefore, the results of staff's offsite consequence analysis, the finding that worst-case meteorological conditions are unlikely to occur with any significant frequency, the finding

that the sparsely populated area would be very easy to evacuate should a release of aqueous ammonia occur, and the finding that the engineering controls proposed to be implemented by the applicant and those required by staff for the storage and transfer of aqueous ammonia are adequate and appropriate, staff concludes that the use, storage and handling of aqueous ammonia will not cause a significant impact.

Hydrochloric Acid

Hydrochloric acid (HCl) would be used initially for cleaning of the HRSGs, and then once every 3-5 years. Due to previous concerns expressed by the Energy Commission staff, modeling for an accidental release of hydrochloric acid was performed by the applicant. Two scenarios were assessed for an uncontrolled release from a tank: the worst-case scenario assumed wind speed of 1.0 m/s, ambient temperature of 100°F, and stability class F; and the second scenario assumed wind speed of 5.0 m/s, ambient temperature of 100°F, and stability class D. Both scenarios assumed a loss of 10,000 pounds of hydrochloric acid, the worst case with a rate of 1.82 kg/s and the second with a rate of 6.35 kg/s as calculated with the NOAA methodology. A surface area of approximately 3,283 square feet and 1 centimeter deep was assumed. The results of the worst-case scenario predicted an airborne concentration of HCl of 50 ppm at 1.5 miles from the HRSGs, and a concentration of approximately 2,000 ppm at the site boundary, and in the range of 250 ppm at the nearest residence. The second scenario modeled predicted a concentration of 50 ppm at 1.2 miles, a concentration of over 2,000 ppm at the site boundary, and approximately 200 ppm at the nearest residence. According to the AFC, the nearest residence to the release point is approximately 0.52 miles southwest (BEP II 2002d, Page 7.9-25).

To assess the potential impacts associated with an accidental release of either anhydrous or aqueous ammonia, staff uses three "bench mark" exposure levels of hydrogen chloride gas. These include:

1. The IDLH level of 50 ppm.
2. The public Emergency Exposure Guidance Level (EEGL) of 20 ppm, developed by the National Research Council for short-term public exposures, and is protective against severe effects.
3. The Cal-EPA 1-hour acute Reference Exposure Level (acute REL) of 1.4 ppm developed by the Office of Environmental Health Hazard Assessment to protect against mild irritative effects on the respiratory system.

Staff considers the NRC EEGL of 20 ppm to be the most useful bench mark in determining the potential for significant risk.

Staff has reviewed the applicant's modeling of an accidental release of hydrochloric acid and determined that all off-site airborne levels predicted by the applicant's modeling under both meteorological scenarios are considerably in excess of all three bench mark levels used by staff to assess impacts to public health. Thus, were staff to accept these modeling results, staff would find that a significant risk of adverse health effects would likely occur with a spill of HCl. However, staff conducted its own modeling using the U.S. EPA SCREEN3 air dispersion model. Staff has traditionally used SCREEN3 to predict the worst-case ground level concentrations and impacts due to hazardous materials releases. Although it tends to over-estimate these levels, it does so to a lesser degree than the ALOHA model which has difficulty assessing the emissions of gases from an aqueous solution. Staff assumed that 30% HCl in water would be used (this is consistent with other power plant projects) and that an accidental spill would result in a pool with a surface area of 3,283 square feet. (The spill was assumed to be limited to a reasonable size by taking into consideration an assumed location of the temporary HCl storage tank on-site, the slope of the area towards drains or berms, and immediate containment efforts.) Staff found that under F stability with 1 m/s wind speed, the airborne concentration predicted to occur at the fenceline (assumed to be 695 feet from the location of the temporary storage tank based on a review of AFC Figure 2.0-4) would be 1,065 ppm and 81 ppm at the nearest residence (approximately 3628 feet away). This compares to the applicant's modeling which predicts 2,000 ppm at the fenceline and approximately 500 ppm at the nearest residence. Staff also found that under D stability with 5 m/s wind speed, the airborne concentration predicted to occur at the fenceline would be 206 ppm and 12 ppm at the nearest residence. This compares to the applicant's modeling which predicts 2,000 ppm at the fenceline and approximately 250 ppm at the nearest residence.

The airborne concentrations predicted by staff's modeling for the worst-case meteorological conditions are in excess of the EEGL of 20 ppm. Staff also found that for more likely meteorological conditions of D stability and winds of 5 m/s, the predicted airborne concentration of HCl at the nearest residence (12 ppm) would be below the EEGL. Furthermore, as per staff's usual method of analysis, staff has determined that because HCl would be used only temporarily, infrequently, and not stored on-site continuously, staff finds that the risk of an accident resulting in a spill during worst-case meteorological conditions to be a very remote and insignificant probability. Nevertheless, the airborne concentrations both on and off-site are significant and must be mitigated. Therefore, staff proposes Condition of Certification **HAZ-9** which would require the use of temporary containment berm(s) to limit the size of a spill of any chemical used to clean the HRSG to no more than 500 square feet. If this condition is required then staff concludes that the engineering controls proposed to be implemented by the applicant, along with those required by staff, for the storage and transfer of hydrochloric acid, will ensure that any accidental release of hydrochloric acid used for the project will not cause a significant impact.

Natural Gas

Natural gas poses a fire and/or possible explosion risk as a result of its flammability. Natural gas is composed of mostly methane, but also contains ethane, propane, nitrogen, butane, isobutene, and isopentane. It is colorless, odorless, and tasteless and is lighter than air. Natural gas can cause asphyxiation when methane is ninety percent in concentration. Methane is flammable when mixed in air at concentrations of 5 to 14 percent, which is also the detonation range. Natural gas, therefore, poses a risk of fire and/or possible explosion if a release were to occur under certain specific conditions. However, it should be noted that, due to its tendency to disperse rapidly (Lees 1998), natural gas is less likely to cause explosions than many other fuel gases, such as propane or liquefied petroleum gas.

While natural gas will be used in significant quantities, it will not be stored on-site. The risk of a fire and/or explosion on-site can be reduced to insignificant levels through adherence to applicable codes and development and implementation of effective safety management practices. In particular, gas explosions can occur in the heat recovery steam generator (HRSG) and during start-up. The National Fire Protection Association (NFPA 85A) requires 1) the use of double block and bleed valves for gas shut-off; 2) automated combustion controls; and 3) burner management systems. These measures will significantly reduce the likelihood of an explosion in gas-fired equipment. Additionally, start-up procedures would require air purging of the gas turbines prior to start-up, thus precluding the presence of an explosive mixture. The safety management plan proposed by the applicant would address the handling and use of natural gas and significantly reduce the potential for equipment failure due to improper maintenance or human error.

Since the proposed facility would tap into the gas line constructed as part of the approved BEP, and will not require the construction of a new gas pipeline off-site, impacts from gas pipelines are not evaluated in this document.

Cooling System Materials

BEP II is proposing to use a wet cooling system with makeup water taken from the raw water storage system. Raw water will be pumped from on-site wells and treated with sodium hypochlorite, sulfuric acid, calcium chloride, an antiscalant, and caustic at an on-site treatment plant. The circulating water in the cooling system would be conditioned to minimize corrosion and control for the formation of mineral scale and biofouling. Chemicals added for these purposed will include sulfuric acid, an organic phosphate solution, and a biocide such as sodium hypochlorite (BEP II 2002d, Section 2.2.8.5). Any risks associated with chemical usage in cooling water would be adequately mitigated through compliance with the appropriate federal, state, and local requirements for hazardous materials use, and compliance staff’s proposed conditions of certification.

Transportation of Hazardous Materials

Hazardous materials, including aqueous ammonia, sulfuric acid, and cleaning chemicals, will be transported to the facility via tanker truck. While many types of hazardous materials will be transported to the site, staff believes that transport of aqueous ammonia poses the predominant risk associated with hazardous materials transport due its volatility and frequency of delivery. If anhydrous ammonia is chosen as the refrigerant, it will be necessary to transport this hazardous material to the site for initial charging of the refrigeration system, again every four to five years to recharge the system after small losses, and possibly once more to drain and completely refill the system. Although only a very small amount of anhydrous ammonia would be used at BEP II to recharge the system (~300 pounds) every 4 - 5 years, the tanker truck transporting the ammonia to BEP II would be just one of several deliveries to other locations and thus the tanker truck could contain varying amounts of anhydrous ammonia up to the tanker volume of 30,000 pounds. During the initial charge and the possible drain and recharge, a fully loaded tanker would be required. Thus, during the 30-year life of the project, a total of nine (9) deliveries of anhydrous ammonia could occur. Staff has previously found in other siting cases that this small number of trips would present an insignificant risk of accidental release to the public. Furthermore, the same on-site precautions and training for the use of anhydrous ammonia in the refrigeration system and the same off-site emergency response capabilities would be more than adequate to address and respond to any accidental release from these occasional tanker truck deliveries. Staff therefore finds that the transport of anhydrous ammonia to the facility for use as a refrigerant would present an insignificant risk, certainly much less than that presented and assessed for the delivery of aqueous ammonia.

Staff reviewed the Applicant's proposed transportation routes for hazardous materials delivery (BEP II 2002d, AFC Section 7.4.2.2). Ammonia can be released during a transportation accident and the extent of impact in the event of such a release would depend on the location of the accident and on the rate of dispersion of ammonia vapor from the surface of the aqueous ammonia pool. The likelihood of an accidental release during transport is dependent on three factors:

- the skill of the tanker truck driver,
- the type of vehicle used for transport, and
- accident rates.

To address this concern, staff evaluated the risk of an accidental transportation release in the project area. Staff's analysis focused on the project area after the delivery vehicle leaves the main highway (I-10, US-95 or SR-78). Staff believes that it is appropriate to rely on the extensive regulatory program that applies to shipment of hazardous materials on California Highways to ensure safe handling in general transportation (see The Federal Hazardous Materials Transportation Law 49 USC §5101 et seq, The US Department of Transportation Regulations 49 CFR Subpart H, §172-700, and California DMV Regulations on Hazardous Cargo). These regulations also address the issue of driver competence. See AFC section 7.4 for additional information on regulations governing the transportation of hazardous materials.

To address the issue of tank truck safety, aqueous ammonia will be delivered to the proposed facility in Department of Transportation (DOT) certified vehicles with design capacity of 6,000 gallons. These vehicles will be designed to DOT Code MC-307. These are high integrity vehicles designed for hauling of caustic materials such as ammonia. Staff has, therefore, proposed Condition of Certification **HAZ-8** to ensure that regardless of which vendor supplies the aqueous ammonia, delivery will be made in a tanker, which meets or exceeds the specifications described by these regulations.

To address the issue of accident rates, staff reviewed the technical and scientific literature on hazardous materials transportation (including tanker trucks) accident rates in the United States and California. Staff relied on six references and three federal government databases to assess the risks of a hazardous materials transportation accident.

Staff used the data from the Davies and Lees (1992) article which references the 1990 Harwood et al. study, to determine that the frequency of release for transportation of hazardous materials in the U.S. is between 0.06 and 0.19 releases per million miles traveled on well designed roads and highways. The maximum usage of aqueous ammonia each year of operation of the proposed BEP II will require about 9 tanker truck deliveries of aqueous ammonia per month (approximately 108 per year) each delivering about 5,000 gallons. Each delivery will travel approximately 2.5 miles between I-10 and the facility per delivery along Neighbors Blvd. to Hobsonway to Buck Blvd. to the facility (the shortest and most direct way). The result is about 270 miles of delivery tanker truck travel in the project area per year. Staff finds that the risk over this distance is insignificant. Data from the U.S. DOT show that the actual risk of a fatality over the past five years from all modes of hazardous material transportation (rail, air, boat, and truck) is approximately 0.1 in one million.

Staff therefore believes the risk of exposure to significant concentrations of aqueous ammonia during transportation to the facility are insignificant because of the remote possibility of accidental release of a sufficient quantity to present a danger to the public. The transportation of similar volumes of hazardous materials on the nation's highways is not unique nor an infrequent occurrence. Staff's analysis of the transportation of aqueous ammonia to the proposed facility (along with data from the U.S. DOT) demonstrates that the risk of accident and exposure is less than significant.

Based on the environmental mobility, toxicity, quantities present at the site and frequency of delivery, it is staff's opinion that aqueous ammonia poses the predominate risk associated with hazardous materials transportation and use at the proposed facility. Based on this, staff concludes that the risk associated with transportation of other hazardous materials to the proposed facility does not significantly increase the risk of impact beyond that associated with ammonia transportation.

Seismic Issues

The possibility exists that an earthquake would cause the failure of a hazardous materials storage tank. The quake could also cause the failure of the secondary containment system (berms and dikes) as well as electrically controlled valves and pumps. The failure of all these preventive control measures might then result in a vapor cloud of hazardous materials moving off-site and impacting the residents and workers in the surrounding community. The effects of the Loma Prieta earthquake of 1989, the Northridge earthquake of 1994, and the earthquake in Kobe, Japan, in January 1995, heighten the concern regarding earthquake safety.

Information obtained after the January 1994 Northridge earthquake showed that some damage was caused to several large storage tanks and smaller tanks associated with the water treatment system of a cogeneration facility. Those tanks with the greatest damage, including seam leakage, were older tanks, while the newer tanks sustained displacements and failures of attached lines. Therefore, staff conducted an analysis of the codes and standards, which should be followed in adequately designing and building storage tanks and containment areas to withstand a large earthquake. The proposed facility would be designed and constructed to the applicable standards of the Universal Building Code (UBC) and the California Building Code (CBC) for Seismic Zone 3 (BEP II 2002d Page 7.9-2).

CUMULATIVE IMPACTS

Staff reviewed the potential for the operation of the BEP II combined with existing facilities to result in cumulative impacts on the population within the area. The facility that has the most potential to contribute to cumulative impacts is the existing BEP I facility located adjacent to the proposed project site with about 1600 feet separating the proposed BEP II ammonia storage area from the existing BEP I ammonia storage area. In the event of an accidental release of ammonia from both facilities at the same time, cumulative impacts would represent a higher concentration of ammonia in areas where the cloud of gas would overlap and an increase in the impacted zone. However, staff finds that it is unlikely that an accidental release that has very low probability of occurrence (about one in one million per year) would independently occur at the BEP II site and BEP I at the same time. Staff also finds that the facility, as proposed by the applicant and with the additional mitigation measures proposed by staff, poses a minimal risk of accidental release that could result in off-site impacts. Therefore, staff concludes that the facility would not contribute to a significant cumulative impact.

APPLICANT'S PROPOSED MITIGATION

The potential for accidents resulting in the release of hazardous materials is greatly reduced by the implementation of a safety management program, which includes the use of both engineering and administrative controls. Elements of facility controls and the safety management plan are summarized below.

ENGINEERING CONTROLS

Engineering controls help to prevent accidents and releases (spills) from moving off-site and impacting the community by incorporating engineering safety design criteria into the design of the facility. The engineered safety features proposed by the applicant for use at this facility include:

- construction of curbs, berms, and/or catchment basins surrounding each of the hazardous materials storage areas to contain accidental releases that might happen during storage or delivery;
- physical separation of stored chemicals in separate containment areas in order to prevent accidental mixing of incompatible materials which may result in the evolution and release of toxic gases or fumes;
- construction of a diked containment area surrounding the truck unloading area; and
- process protective systems including continuous tank level monitors, temperature and pressure monitors, alarms, check valves, emergency block valves, and double-walled piping when needed.

ADMINISTRATIVE CONTROLS

Administrative controls also help to prevent accidents and releases (spills) from moving off-site and impacting the community by establishing worker training programs, process safety management programs and by complying with all applicable health and safety laws, ordinances and standards.
A worker health and safety program will be prepared by the applicant and will include (but is not limited to) the following elements:

- worker training regarding chemical hazards, health and safety issues, and hazard communication;

- procedures to ensure the proper use of personal protective equipment;
- safety operating procedures for operation and maintenance of systems utilizing hazardous materials;
- fire safety and prevention; and
- emergency response actions including facility evacuation, hazardous material spill cleanup, and fire prevention.

At the facility, the project owner will be required to designate an individual who has the responsibility and authority to ensure a safe and healthful workplace. The project health and safety official will oversee the health and safety program and will have the authority to halt any action or modify any work practice in order to protect the workers, facility, and the surrounding community in the event that the health and safety program is violated.

ON-SITE SPILL RESPONSE

In order to address the issue of spill response, the facility will prepare and implement an Emergency Response Plan which includes information on: hazardous materials contingency and emergency response procedures, spill containment and prevention systems, personnel training, spill notification, on-site spill containment, prevention equipment and capabilities, etc. Emergency procedures will be established which include evacuation, spill cleanup, hazard prevention, and emergency response.

The City of Blythe Fire Department (BFD) fire station located at 201 North Commercial Street approximately 5 miles away is considered first responder for HazMat incidents, with backup service provided by the Riverside County Fire Department (RCFD) stations 43 and 45. BFD has a response time of 10 minutes (HRC 2000). Currently, the BFD fire station and RCFD stations 43 and 45 do not have any trained hazmat technicians. Additional response would be provided by the Riverside County HazMat Response Team located in Beaumont, approximately two hours away and manned with 4 Hazmat technicians (BEP II 2002d Page 7.6-8, HRC 2000, and RCFD 2003b).

The needs assessment conducted for BEP I indicates that the present HazMat resources may not result in timely response to spills. The needs assessment concluded that “the BEP I power plant must build-in all feasible mitigations to reduce the hazardous materials threat, and must provide for the response of trained, private hazardous materials clean-up companies from Los Angeles or Phoenix, to clean up hazardous waste after a release (HRC 2000).” According to the City of Blythe Fire Department (BFD 2003), the mitigation measure chosen by BEP I was to train all personnel at BEP I to the level of Hazmat Technicians, which are capable of complete hazmat response including extraction. The BFD also suggested that BEP II should either pay the BFD and RCFD for training to bring their staff up to the level of Hazmat Technicians, or train their own staff as they did at BEP I (BFD 2003).

Staff proposes a Worker Safety/Fire Protection Condition of Certification that would require the applicant to train BEP II personnel to the level of Hazmat Technicians as in the original BEP in order to reduce the response time to an adequate one and reduce the potential impacts from a HazMat incident to insignificant.

STAFF'S PROPOSED MITIGATION

Staff proposes eight Conditions of Certification mentioned throughout the text (above) and listed below. **HAZ-1** ensures that no hazardous material would be used at the facility except those listed in the AFC unless there is prior approval by the County and the California Energy Commission Compliance Project Manager (CPM). **HAZ-2** requires that a RMP be prepared and submitted prior to the delivery of aqueous **or anhydrous** ammonia.

Staff believes that an accidental release of aqueous ammonia during transfer from the delivery tanker to the storage tank is the most probable accident scenario, and therefore; proposes a condition (**HAZ-3**) requiring development of a safety management plan for the delivery of aqueous ammonia. The development of a Safety Management Plan addressing delivery of ammonia will further reduce the risk of any accidental release not addressed by the proposed spill prevention mitigation measures and the required Risk Management Plan (RMP). **HAZ-4** requires that the aqueous ammonia storage tank be designed to certain rigid specifications, **HAZ-5** addresses the storage of sulfuric acid, the transportation of hazardous materials is addressed in **HAZ-6,** & **7**, and **HAZ-8** addresses the use of anhydrous ammonia as a refrigerant should the applicant choose this chemical as the refrigerant for the inlet chiller. **HAZ-9** will reduce the impacts of any chemical spill, including HCl, during HRSG cleaning to an insignificant level.

SITE SECURITY

This facility proposes to use hazardous materials that have been identified by the US EPA as materials where special site security measures should be developed and implemented to ensure that unauthorized access is prevented. The EPA published a Chemical Accident Prevention Alert regarding Site Security (EPA 2000a), the US Department of Justice published a special report on Chemical Facility Vulnerability Assessment Methodology (US DOJ 2002), the North American Electric Reliability Council published Security Guidelines for the Electricity Sector in 2002 (NAERC 2002), and the U.S. Department of Energy published a draft Vulnerability Assessment Methodology for Electric Power Infrastructure in 2002 (DOE 2002). In order to ensure that this facility or a shipment of hazardous material is not the target of unauthorized access, staff's proposed General Condition of Certification on Construction and Operations Security Plan **COM-8** (see the **GENERAL CONDITIONS** section of this FSA) will require the preparation of a Vulnerability Assessment and the implementation of Site Security measures consistent with the above-referenced documents and CEC guidelines.

The level of security needed for this power plant is dependent upon the threat imposed, the likelihood of an adversary attack, the likelihood of adversary success in causing a catastrophic event, and the severity of consequences of that event. In order to determine the level of security, the CEC staff will provide guidance in the form of a vulnerability assessment (VA) decision matrix modeled after the U.S. Department of Justice Chemical Vulnerability Assessment Methodology (July 2002) and the U.S. Department of Energy VAM-CF model (DOE 2003). Basic site security measures shall be required at all locations in order to protect the infrastructure and electrical power generation within the state. These measures will include perimeter fencing and detectors, guards, alarms, site access for employees and vendors, site personnel background checks, and law enforcement contact in the event of security breach. Other locations will have additional security measures dependent upon the results of the vulnerability assessment. The vulnerability assessment will be based, in part, on the use and storage of certain quantities of hazardous materials, including acutely hazardous materials as described by the California Accidental Release Prevention Program (Cal-ARP; Health and Safety Code, § 25531), hydrogen gas, Liquified Petroleum Fuels, sulfuric acid in concentrations greater than 90%, and any material poisonous by inhalation as defined in 49 CFR §171.8. The results of the off-site consequence analysis (OCA) prepared as part of the Risk Management Plan (RMP) will be used, among other tools, to determine the severity of consequences of a catastrophic event.

Site access for vendors shall be strictly controlled. Consistent with current state and federal regulations governing the transport of hazardous materials, hazardous materials vendors will have to maintain their transport vehicle fleet and employ only drivers properly licensed and trained. The project owner will be required, through the use of contractual language with vendors, to ensure that vendors supplying hazardous materials strictly adhere to the U.S. Department of Transportation (DOT) requirements for Hazardous Materials vendors to prepare and implement security plans as per 49 CFR 172.800 and to ensure that all hazardous materials drivers are in compliance with personnel background security checks as per 49 CFR Part 1572, Subparts A and B.

The CPM may authorize modifications to these measures, or may require additional measures depending on circumstances unique to the facility, and in response to site operator and/or industry-related security concerns.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this Staff Assessment, or figure 7.6-7 of the AFC). However, as indicated in **Socioeconomics Figure 1**, there are 2 census blocks with greater than 50 percent minority persons within the six-mile radius; staff considers these to be pockets or clusters. One of these minority pockets (census tract 458) includes both BEP I and BEP II in the eastern portion of the Tract. This Tract includes the Mesa Verde community located approximately 2.25 miles southwest of the BEP II site (BEP II 2002d Section 7.6.3 and Figure 7.6-7). Staff also reviewed Census 1990 information that shows the low-income population is less than fifty percent within the same radius. Because staff has determined there to be pockets or clusters of minority population within the six-mile radius, staff has conducted a focused environmental justice analysis for **Hazardous Materials Management**.

Based on the analysis presented in this document, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project, and therefore there are no environmental justice issues from the use or transport of hazardous materials related to this project.

FACILITY CLOSURE

The requirements for handling of hazardous materials remain in effect until such materials are removed from the site regardless of facility closure. Therefore, the facility owners are responsible for continuing to handle such materials in a safe manner, as required by applicable laws. The **General Conditions** section of this report discusses planned, unexpected temporary, and unexpected permanent closure. Staff's General Conditions for Facility Closure require preparation of an on-site contingency plan, which must provide for removal of hazardous wastes and draining of all chemicals from storage tanks and other equipment for temporary closures exceeding 90 days or for unexpected permanent closure.

For planned permanent closure, BEP II would develop a facility closure plan at least twelve months prior to commencement of closure and is committed to complying with LORS which are applicable at the time of closure.

In the event that the facility owner abandons the facility in a manner which poses a risk to surrounding populations, staff will coordinate with the California Office of Emergency Services, Riverside County Hazardous Materials Division, and the California Department of Toxic Substances Control (DTSC) to ensure that any unacceptable risk to the public is eliminated. Funding for such emergency action can be provided by federal, state or local agencies until the cost can be recovered from the responsible parties.

CONCLUSIONS AND RECOMMENDATIONS

Staff's evaluation of the proposed project (with staff's proposed mitigation measures) indicates that hazardous materials use will pose little potential for significant impacts on the public. With adoption of the proposed Conditions of Certification, the proposed project will comply with all applicable Laws, Ordinances, Regulations and Standards (LORS). In response to Health and Safety Code, section 25531 et seq., the applicant will be required to develop an RMP. To insure adequacy of the RMP, staff's proposed Conditions of Certification require that the RMP be submitted for concurrent review by US EPA, Riverside County, and CEC staff. In addition, staff's proposed Conditions of Certification require Riverside County's review, and staff review and approval of the RMP prior to delivery of any hazardous materials to the facility. Other proposed Conditions of Certification address the issue of the transportation, storage, and use of aqueous ammonia and the use of anhydrous ammonia as a refrigerant.

Staff recommends the Energy Commission impose the proposed Conditions of Certification, presented herein, to ensure that the project is designed, constructed and operated to comply with applicable LORS and to protect the public from significant risk of exposure to an accidental ammonia release. If all mitigation proposed by the applicant and by staff are required, the use, storage, and transportation of hazardous materials will not present a significant risk to the public.

PROPOSED CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous materials not listed in Appendix C, below, or in greater quantities than those identified by chemical name in Appendix C, below, unless approved in advance by the CPM.

Verification: The project owner shall provide to the Compliance Project Manager (CPM), in the Annual Compliance Report, a list of hazardous materials contained at the facility.

HAZ-2 The project owner shall concurrently provide a Business Plan and a Risk Management Plan (RMP) to the Certified Unified Program Authority – (CUPA) (Riverside County Hazardous Materials Division) and the CPM for review at the time the RMP is first submitted to the U.S. Environmental Protection Agency (EPA). After receiving comments from the CUPA, the EPA, and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final Business Plan and RMP shall then be provided to the CUPA and EPA for information and to the CPM for approval.

Verification: At least 60 days prior to receiving any hazardous material on the site, the project owner shall provide a copy of a final Business Plan to the CPM for approval. At least sixty (60) days prior to delivery of aqueous ammonia to the site, the project owner shall provide the final RMP to the CUPA for information and to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of aqueous ammonia. The plan shall include procedures, protective equipment requirements, training and a checklist. It shall also include a section describing all measures to be implemented to prevent mixing of aqueous ammonia with incompatible hazardous materials.

Verification: At least sixty (60) days prior to the delivery of aqueous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-4 The aqueous ammonia storage facility shall be designed to either the ASME Pressure Vessel Code and ANSI K61.6 or to API 620. In either case, the storage tank shall be protected by a secondary containment basin capable of holding 125% of the storage volume or the storage volume plus the volume associated with 24 hours of rain assuming the 25-year storm. The final design drawings and specifications for the ammonia storage tank and secondary containment basins shall be submitted to the CPM.

Verification: At least sixty (60) days prior to delivery of aqueous ammonia to the facility, the project owner shall submit final design drawings and specifications for the ammonia storage tank and secondary containment basin to the CPM for review and approval.

HAZ-5 The project owner shall ensure that no flammable material is stored within 50 feet of the sulfuric acid tank.

__**Verification:**__ At least sixty (60) days prior to receipt of sulfuric acid on-site, the Project Owner shall provide copies of the facility design drawings showing the location of the sulfuric acid storage tank and the location of any tanks, drums, or piping containing any flammable materials

HAZ-6 The project owner shall direct all vendors delivering aqueous ammonia to the site to use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code MC-307

__**Verification:**__ At least sixty (60) days prior to receipt of aqueous ammonia on site, the project owner shall submit copies of the notification letter to supply vendors indicating the transport vehicle specifications to the CPM for review and approval.

HAZ-7 The project owner shall direct all vendors delivering any hazardous material to the site to use only the route approved by the CPM (I-10 to Neighbors Blvd. to Hobsonway to Buck Blvd). The project owner shall obtain approval of the CPM if an alternate route is desired.

__**Verification**__**:** At least sixty (60) days prior to receipt of any hazardous materials on site, the project owner shall submit copies of the required transportation route limitation direction to the CPM for review and approval.

HAZ-8 If anhydrous ammonia is chosen for use as the inlet chiller refrigerant, the project owner shall develop and implement an Ammonia Refrigeration Hazard Reduction Plan. This plan shall include procedures, protective equipment requirements, training and a checklist, as described in the August 2001 EPA Chemical Safety Alert. It shall also include a section describing all measures to be implemented to prevent the leaking of anhydrous ammonia from the refrigeration system. This plan shall also incorporate recommended practices as found in ANSI Standards 15-2001 and 34-2001 and the ASHRAE Position Document on Ammonia As A Refrigerant (January 17, 2002). The applicant shall also include appropriate elements of the Cal-OSHA Process Safety Management standard (8 CCR section 5189).

__**Verification**__**:** At least sixty (60) days prior to the delivery of anhydrous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-9 When cleaning the HRSG, the project owner shall provide or contract to provide temporary berm(s) to contain any spill of any cleaning chemical to no more than 500 square feet in size.

__**Verification:**__ At least sixty (60) days prior to delivery of the initial HRSG cleaning chemicals to the site, the project owner shall submit final design drawings and specifications for the temporary surface containment berm(s) to the CPM for review and approval.

HAZ-10 The project owner shall install an approved automatic fire suppression system on the ammonia refrigeration plant.

Verification: At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide final design drawings and specification for the fire protection system approved by a registered Safety Engineer to the CPM for review and approval.

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APPENDIX A

HAZARDOUS MATERIAL MANAGEMENT

BASIS FOR STAFF'S USE OF 75 PPM AMMONIA EXPOSURE CRITERIA

Staff uses a health-based airborne concentration of 75 PPM to evaluate the significance of impacts associated with potential accidental releases of ammonia. While this level is not consistent with the 200-ppm level used by EPA and Cal/EPA in evaluating such releases pursuant the Federal Risk Management Program and State Accidental Release Program, it is appropriate for use in staff's CEQA analysis. The Federal Risk Management Program and the State Accidental Release Program are administrative programs designed to address emergency planning and ensure that appropriate safety management practices and actions are implemented in response to accidental releases. However, the regulations implementing these programs do not provide clear authority to require design changes or other major changes to a proposed facility. The preface to the Emergency Response Planning Guidelines (ERPGs) states that "these values have been derived as planning and emergency response guidelines, **not** exposure guidelines, they do not contain the safety factors normally incorporated into exposure guidelines. Instead they are estimates, by the committee, of the thresholds above which there would be an unacceptable likelihood of observing the defined effects." It is staff's contention that these values apply to healthy adult individuals and are levels that should not be used to evaluate the acceptability of avoidable exposures for the entire population. While these guidelines are useful in decision making in the event that a release has already occurred (for example, prioritizing evacuations), they are not appropriate for and are not binding on discretionary decisions involving proposed facilities where many options for mitigation are feasible. CEQA requires permitting agencies making discretionary decisions to identify and mitigate potentially significant impacts through changes to the proposed project.

Staff has chosen to use the National Research Council's 30 minute Short Term Public Emergency Limit (STPEL) for ammonia to determine the potential for significant impact. This limit is designed to apply to accidental unanticipated releases and subsequent public exposure. Exposure at this level should not result in serious effects but would result in "strong odor, lacrimation, and irritation of the upper respiratory tract (nose and throat), but no incapacitation or prevention of self-rescue." It is staff's opinion that exposures to concentrations above these levels pose significant risk of adverse health impacts on sensitive members of the general public. It is also staff's position that these exposure limits are the best available criteria to use in gauging the significance of public exposures associated with potential accidental releases. It is, further, staff's opinion that these limits constitute an appropriate balance between public protection and mitigation of unlikely events, and are useful in focusing mitigation efforts on those release scenarios that pose real potential for serious impacts on the public. Table 1 provides a comparison of the intended use and limitations associated with each of the various criteria that staff considered in arriving at the decision to use the 75-ppm STPEL. Appendix B provides a summary of adverse effects, which might be expected to occur at various airborne concentrations of ammonia.

Acute Ammonia Exposure Guidelines

Guideline	Responsible Authority	Applicable Exposed Group	Allowable Exposure Level	Allowable* Duration of Exposures	Potential Toxicity at Guideline Level/Intended Purpose of Guideline
IDLH[2]	NIOSH	Workplace standard used to identify appropriate respiratory protection.	300 ppm	30 min.	Exposure above this level requires the use of “highly reliable” respiratory protection and poses the risk of death, serious irreversible injury or impairment of the ability to escape.
IDLH/10[1]	EPA, NIOSH	Work place standard adjusted for general population factor of 10 for variation in sensitivity	30 ppm	30 min.	Protects nearly all segments of general population from irreversible effects
STEL[2]	NIOSH	Adult healthy male workers	35 ppm	15 min. 4 times per 8 hr day	No toxicity, including avoidance of irritation
EEGL[3]	NRC	Adult healthy workers, military personnel	100 ppm	Generally less than 60 min.	Significant irritation but no impact on personnel in performance of emergency work; no irreversible health effects in healthy adults. Emergency conditions one time exposure
STPEL[4]	NRC	Most members of general population	50 ppm 75 ppm 100 ppm	60 min. 30 min. 10 min.	Significant irritation but protects nearly all segments of general population from irreversible acute or late effects. One time accidental exposure
TWA[2]	NIOSH	Adult healthy male workers	25 ppm	8 hr.	No toxicity or irritation on continuous exposure for repeated 8 hr. Work shifts
ERPG-2[5]	AIHA	Applicable only to emergency response planning for the general population (evacuation) (not intended as exposure criteria) (see preface attached)	200 ppm	60 min.	Exposures above this level entail** unacceptable risk of irreversible effects in healthy adult members of the general population (no safety margin)

1) (EPA 1987) 2) (NIOSH 1994) 3) (NRC 1985) 4) (NRC 1972) 5) (AIHA 1989)

* The (NRC 1979), (WHO 1986), and (Henderson and Haggard 1943) all conclude that available data confirm the direct relationship to increases in effect with both increased exposure and increased exposure duration.

** The (NRC 1979) describes a study involving young animals, which suggests greater sensitivity to acute exposure in young animals. The (WHO 1986) warns that the young, elderly, asthmatics, those with bronchitis and those that exercise should also be considered at increased risk based on their demonstrated greater susceptibility to other non-specific irritants.

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Abbreviations for Appendix A, Table 1

ACGIH, American Conference of Governmental and Industrial Hygienists
AIHA, American Industrial Hygienists Association
EEGL, Emergency Exposure Guidance Level
EPA, Environmental Protection Agency
ERPG, Emergency Response Planning Guidelines
IDLH, Immediately Dangerous to Life and Health Level
NIOSH, National Institute of Occupational Safety and Health
NRC, National Research Council
STEL, Short Term Exposure Limit
STPEL, Short Term Public Emergency Limit
TLV, Threshold Limit Value
WHO, World Health Organization

Appendix B

SUMMARY OF ADVERSE HEALTH EFFECTS OF AMMONIA

638 PPM

WITHIN SECONDS:

∉ Significant adverse health effects;

∉ Might interfere with capability to self rescue;

∉ Reversible effects such as severe eye, nose and throat irritation.

AFTER 30 MINUTES:

∉ Persistent nose and throat irritation even after exposure stopped;

∉ irreversible or long-lasting effects possible: lung injury;

∉ Sensitive people such as the elderly, infants, and those with breathing problems (asthma) experience difficulty in breathing;

∉ asthmatics will experience a worsening of their condition and a decrease in breathing ability, which might impair their ability to move out of area.

266 PPM

WITHIN SECONDS:

∉ Adverse health effects;

∉ Very strong odor of ammonia;

∉ Reversible moderate eye, nose and throat irritation.

AFTER 30 MINUTES:

∉ Some decrease in breathing ability but doubtful that any effect would persist after exposure stopped;

∉ Sensitive persons: experience difficulty in breathing;

∉ asthmatics: may have a worsening condition and decreased breathing ability, which might impair their ability to move out of the area.

64 PPM

WITHIN SECONDS:

∉ Most people would notice a strong odor;

∉ Tearing of the eyes would occur;

∉ Odor would be very noticeable and uncomfortable.

∉ Sensitive people could experience more irritation but it would be unlikely that breathing would be impaired to the point of interfering with capability of self rescue

∉ Mild eye, nose, or throat irritation

- Eye, ear, & throat irritation in sensitive people
- asthmatics might have breathing difficulties but would not impair capability of self rescue

22 or 27 PPM

WITHIN SECONDS:

- Most people would notice an odor;
- No tearing of the eyes would occur;
- Odor might be uncomfortable for some;
- sensitive people may experience some irritation but ability to leave area would not be impaired;
- Slight irritation after 10 minutes in some people.

4.0, 2.2, or 1.6 PPM

- No adverse effects would be expected to occur;
- Doubtful that anyone would notice any ammonia (odor threshold 5 - 20 PPM);
- Some people might experience irritation after 1 hr.

- Appendix C

[Attach here AFC Table 7.9-2 from the revised Hazardous Materials Handling section Dated July 7, 2003.]

LAND USE

Ken Peterson

INTRODUCTION

The land use analysis of the Blythe Energy Project Phase II (BEP II) focuses on two main issues: (1) project consistency with the land use laws, ordinances, regulations standards, plans and policies, and (2) project compatibility with existing and planned land uses. The major concerns with BEP II land use compatibility are the project's potential for direct and indirect impacts on agricultural uses, conflict with airport operations at the Blythe Airport located approximately one mile to the west of the project site, and cumulative impact in combination with other planned projects.

In general, an electric generation project and its related facilities may be incompatible with existing and planned land uses if it creates unmitigated noise, dust, public health hazard or nuisance, traffic, or visual impacts, or when it unduly restricts existing or planned future uses.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

This section describes federal, State, regional, and local land use laws, ordinances, regulations, and standards (LORS) applicable to the proposed project.

FEDERAL

There are no federal land use LORS that affect BEP II. The applicable federal aviation regulations are summarized in the **TRAFFIC and TRANSPORTATION** section.

STATE

Subdivision Map Act (Pub. Resources Code § 66410-66499.58)

The Subdivision Map Act provides procedures and requirements regulating land divisions (subdivisions) and the determining of parcel legality. This Act vests regulation and control of the design and improvement of subdivisions in local municipalities. Each local municipality by ordinance regulates and controls the initial design and improvement of common interest developments and subdivisions for which the Map Act requires a tentative and final map.

LOCAL

County

Although the project facilities are located entirely in the City of Blythe, the applicant's proposed Water Conservation Offset Program (WCOP) could have a significant impact on County agricultural land. Therefore, staff reviewed the Riverside County Comprehensive General Plan (RCCGP) policies relevant to BEP II.

Land Use Element

The RCCGP Land Use Element is the primary policy statement for implementing the development and conservation goals of the County's General Plan. The Countywide policies for land use compatibility, population levels, public facility levels, environmental constraints and community policies are also contained within the General Plan. The County continuously updates the Land Use Element using data on current conditions to revise the General Plan's maps and diagrams.

The Land Use Element contains policies specific to the Palo Verde Valley Area. The overall policy for future land uses in this area is for continued agricultural land uses, with urban uses directed to in the City of Blythe's Sphere of Influence. The Element states that industrial development should occur within this sphere of influence, south of Blythe along the Arizona and California Railroad line (formerly AT&SF) and adjacent to the Blythe Airport (RCCGP, p. 99).

Environmental Hazards and Resources Element

The Environmental Hazards and Resources Element contains an open space and conservation inventory and related map, which delineate those areas that have significant open space or conservation value. These areas may include agricultural lands, parks and recreation areas, vegetation resources, wildlife resources, scenic highways, historic resources, energy resources, fire hazard areas, seismic/geologic hazard areas, slope areas, flood hazard areas, noise impacted areas and other natural resources and hazards. Mapped land uses include open space, recreation, agriculture, mining, research and related compatible land uses (RCCGP, p. 368).

The Open Space and Conservation land use standards include the following: "The open space characteristics of the County, including the rivers, the mountains, the deserts, and the productive agricultural lands shall be protected." (RCCGP, p. 376)

Agriculture objectives include: "1. Agriculturally productive lands shall be encouraged to remain in agricultural uses." (RCCGP, p. 377) Riverside County participates in the Williamson Act Program. Lands placed in agricultural preserve are restricted to agriculture and compatible uses (RCCGP 1984 p. 378) such as electric transmission lines, gas pipelines, low density residential, and flood control structures.

City of Blythe General Plan

Under California State planning law, each incorporated City and County must adopt a comprehensive, long-term General Plan that governs the physical development of all lands under its jurisdiction. The general plan is a broadly scoped planning document and defines large-scale planned development patterns over a relatively long timeframe.

The General Plan consists of a statement of development policies and must include a diagram and text setting forth the objectives, principles, standards and proposals of the document. At a minimum, a General Plan has seven mandatory elements including Land Use; Circulation; Housing; Conservation; Open Space; Noise and Safety.

In September of 1989, the City of Blythe approved a comprehensive general plan for the incorporated City and the City's Sphere of Influence. A much larger study area covering 63 square miles was addressed, but is not under the jurisdiction of the City. The City General Plan applies only to those areas within the City's incorporated boundary and Sphere of Influence[1].

City of Blythe Land Use Element

The City General Plan designation for the power plant site is Heavy Industrial (I-H) (See **LAND USE Figure 1, City of Blythe General Plan Designations**). According to the General Plan, the Heavy Industrial designation provides for the most intense industrial development to be contemplated in the City. Uses associated with this designation may include power plants, slaughter houses, rendering plants, metals smelting and/or manufacturing, refining oils and other flammable or hazardous materials, and other uses which may require extensive outdoor storage areas or materials handling.

The City General Plan land use categories are described below (Blythe1989, p. III-2):

> Agricultural Reserve consists of land in active or potentially active cultivation and sufficiently removed from urban development to warrant protection.
>
> Residential Reserve serves as an intermediate land use designation buffering agricultural lands from urban residential development. This category precludes premature expansion of urban development.
>
> Urban Reserve consists of land in the sphere of influence and outlying planning areas planned for future urban core development. This category requires a specific plan.
>
> Heavy Industrial provides for industrial uses which are relatively intense and which may also include extensive outdoor storage.

Agricultural Land Use Goals and Policies

Although the project site is zoned for heavy industrial use, the agricultural land use goals and policies of the City General Plan are discussed in the LORS section because of the possible impact of the applicant's Water Conservation Offset Program (WCOP) (discussed below) on the implementation of these goals and policies.

The Agricultural Reserve designation is assigned to lands which are in active or potentially active cultivation, and which are sufficiently removed from urban development to warrant protection and preservation. These lands are generally composed of larger holdings, which make ongoing cultivation viable. This designation also may be assigned to areas where farm structures and residences occur, but is not applicable to agriculture-related industrial land uses (Blythe 1989, p. III-26).

Agricultural goals and policies contained in the City Land Use Element encourage the retention of agricultural lands in agricultural use (Blythe 1989, pp. III-25-26). Agricultural Reserve goals relevant to the project are as follows (Blythe 1989, pp. III-25):

[1] Sphere of Influence is defined by Government Code §56076 as a "plan for the probable physical boundaries of a local agency as determined by the Commission (Local Area Formation Commission)."

- To preserve and protect agricultural lands from premature or inappropriate intrusion of urban or other adverse land uses, which threaten the long-term viability of agricultural activities.
- Assure the thoughtful integration of agricultural lands with other land uses, assuring that these lands will continue to provide open space relief from the urban development of the City.

Agricultural Reserve Policies relevant to the project are as follows (Blythe 1989, p. III-26).

- The City shall protect agricultural lands from premature development by assuring the logical and coherent expansion of urban development in the City.
- The City shall encourage the continuation of agricultural activity on undeveloped land as a method of assuring their on-going use and function as rural open space areas.
- Preservation of agricultural lands and prime soils in non-urban areas shall be fostered in order to retain the viability of the groundwater aquifer, which serves the City.

Agricultural Resources Element

The City Agricultural Resources Element contains the following goal which is relevant to the project (Blythe 1989, p. IV-29):

- Maintain, protect and enhance the viability of the agricultural resources of the Palo Verde valley, while providing for increasing urbanization within the City, Sphere and Study Area.

City of Blythe Zoning Ordinance

The City of Blythe Zoning Ordinance establishes land use (zone) districts in the City's incorporated area. In each specific land use district, land uses, dimensions for buildings, and open spaces are regulated for the purpose of implementing the general plan of the City, protecting existing development, encouraging beneficial new development, and preventing overcrowding and congestion.

The City has zoned the power plant site General Industrial (I-G). The General Industrial zone allows a variety of manufacturing uses by right including public maintenance services, utility operations facilities, custom manufacturing, general manufacturing, and warehousing in accordance with §17.08 010 of the City Zoning Ordinance. City zoning designations for lands within one mile of the power plant site are Agriculture (A) to the east, and Service Industrial (I-S) to the south between I-10 and Hobsonway. See **LAND USE Figure 2**, **City of Blythe Zoning.**

RIVERSIDE COUNTY AIRPORT LAND USE COMMISSION

The Comprehensive Land Use Plan

The *Comprehensive Land Use Plan for Blythe Airport, Riverside County, California (CLUP)* was adopted by the Riverside County Airport Land Use Commission (ALUC) in August of 1992. The purpose of the CLUP is to protect and promote safety and welfare of residents of the airport vicinity and users of the airport while ensuring the continued operation of the airport. Where local general plans or specific plans are not consistent with the CLUP, State law enables the ALUC to require the local agencies to submit all development actions, regulations, and permits to the ALUC for review.

The ALUC is established under the authority of California Government Code Sections 21670 et. seq. and is charged with formulating a comprehensive land use plan for the area surrounding each public use airport in its jurisdiction. The ALUC, appointed by the County Board of Supervisors, makes determinations of consistency of proposed development projects on an advisory basis for the permitting jurisdiction. The local permitting agency can overrule a determination by the ALUC by a two-thirds vote of its governing body. However, in the case of certification of energy projects over 50 megawatts the Energy Commission's certifying power takes precedence over local government (Public Resources Code Par. 25505), and the Energy Commission staff shall give due deference to a local government's comments and recommendations (Cal. Code Regs,. Tit. 20, §1714.5)

SETTING

SITE AND VICINITY DESCRIPTION

The BEP II site is located about 5 miles west of downtown Blythe in eastern Riverside County, in a recently-annexed portion of the City of Blythe and about one mile east of the Blythe Airport. The site is located approximately 1,000 feet north of I-10, a major regional transportation corridor extending east-west through the area. **See LAND USE Figure 3**, **Regional Location of the Proposed Project**.

The BEP II power plant site is located within a 1,253-acre area recently annexed to the City, which extends from the City's previous western boundary to the eastern boundary of the Blythe Airport property. The annexation became final on November 28, 2000. The BEP II site is located in an area called Mesa Verde (the Mesa), above the Palo Verde Valley floor.

The project site is located in the Palo Verde Valley area of the County, which is an intensive agricultural region. Commodities grown in the area include citrus, melon, vegetable, and field crops such as alfalfa. Nearly all of the cultivated areas are irrigated with water from the Colorado River aquifer, supplied from the Palo Verde Irrigation District or from domestic wells.

BEP II would be built on the 76-acre expansion portion of the original 76-acre Blythe Energy Project Phase I (BEP) site, on the west side of the original site. The entire BEP

I/BEP II 152-acre site is to the north of and adjacent to Hobsonway, a two-lane arterial road oriented East-West, and to the west and adjacent to Buck Boulevard. Hobsonway is a four-lane local arterial road that connects the Blythe Airport with the City of Blythe. The construction of BEP I has recently been completed on the original site, and the expansion site is unimproved.

SURROUNDING LAND USE

Land uses surrounding the site include the Blythe Airport facilities, large parcel agriculture, electric utilities, highways, and residential and industrial structures. Specific surrounding uses are described as follows with the approximate distances from the project site:

- the Blythe Substation located about 2000 feet to the east;
- the Blythe Airport located approximately one mile to the west;
- an unincorporated residential community within the Mesa Verde area, located approximately 2 miles southwest;
- isolated farm and other residents near the project site, primarily located south and east;
- a small industrial area to the north;
- a small sewage treatment facility about 0.25 mile to the west;
- Interstate 10 corridor approximately 0.25 mile to the south;
- a U.S. Border Patrol facility over one mile to the west; and
- the Blythe Trap Shooting Club and the Riverside County Animal Shelter, both about one mile to the west.

Properties immediately adjacent and to the west, north and south (across Hobsonway) are undeveloped. The property to the immediate east is cultivated with a lemon grove. The Blythe Substation is owned by the Western Area Power Administration. The substation occupies a site approximately 12 acres in size, surrounded on three sides by the lemon grove. The Blythe Substation connects five existing 161-kV transmission lines serving the region.

Except for agriculture and some scattered residences and industrial uses, the properties within one mile of the power plant site are largely undeveloped. Highway-serving commercial uses are located on the north side of Interstate 10 (I-10) at the interchange south of the Blythe Airport. The Blythe Airport is described in detail below.

Blythe is the only incorporated city within the Palo Verde Valley planning area. Unincorporated communities in the Palo Verde Valley Area include Mesa Verde (Nicholl's Warm Springs), located approximately 2 miles southwest of the project site; and Ripley, located approximately 6 miles to the south of the City and the project site. The predominant land use in the area is irrigated agriculture and related enterprises. Other land uses include residential, and recreational development mainly focused on the Colorado River, which borders the City of Blythe on the east. Commercial land uses serve the needs of agriculture, local residents, pass-through travelers, and recreational visitors. I-10 is a major interstate and regional transportation corridor, which extends east-west through the area.

Mesa Verde is the largest concentration of residential land uses in the proximity of the project. The major residential portion of the City of Blythe is located about five miles to the east. There are small numbers of farm and other residents near the site, mostly located south and east of the project site. The nearest residence is located 0.75 mile southwest of the power plant site (BEP II 2002a, p. 7.2-4).

Blythe Airport

The Blythe Airport is located approximately one mile west of the proposed BEP II power plant site. The Blythe Airport is the largest airport serving eastern Riverside County and serves primarily general aviation demand in the Blythe area. The Airport is classified in the National Plan of Integrated Airport Systems as a general aviation transport airport, designed to accommodate business jets, cargo type aircraft, light private planes, and flight school training activities. The Blythe Airport currently has two runways. The primary runway is Runway 8-26, which is oriented generally east-west. The BEP II power plant stacks would be located approximately 4,450 feet southeast of this runway, which is situated at an elevation of 393 feet mean sea level (MSL). The elevation of the BEP II site is about 335 feet MSL (BEP II 2002a, 7.4-8). Therefore the 130-foot HRSG stacks would be about 72 feet higher than the end of the runway. If the project's on-site transmission towers are double circuited, they will be approximately 145 feet tall (BEP II 2003b, p. 41) and about 87 feet higher than the end of the runway. Please refer to the **TRAFFIC AND TRANSPORTATION** section of the PSA for details regarding Blythe Airport operations and facilities.

The Blythe Airport has been designated as a County redevelopment area. The intent is to encourage expansion of airport facilities and commercial and industrial development at the airport. The County's redevelopment plans are described in the Riverside County *Redevelopment Plan for Redevelopment Project Airports*, County of Riverside Economic Development Agency 1988 (Coffman, p. 2-18).

Agriculture

The BEP II power plant site is not currently used for agricultural production, nor does it appear to have been cultivated in the past. The site is classified as Farmland of Local Importance[2]. Similar soil types occur on the irrigated lands immediately adjacent, to the east of the site, which are designated Prime Farmlands[3], and currently contain a lemon grove.

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[2] Farmland of Local Importance is land of importance to the local agricultural economy as determined by each County's board of supervisors and local advisory committees, and noted on the California Department of Conservation Important Farmland Map" for Riverside County (DOC).

[3] Prime Farmland is land that has the best combination of physical and chemical characteristics for the production of crops. It has the soil quality, growing season, and moisture supply needed to produce sustained yields of crops when treated and managed, including water management, according to current farming methods. Prime farmlands must have been in production of irrigated crops at some time during the update cycles prior to the California Department of Conservation's (DOC) Important Farmland mapping date.

PROJECT FEATURES

The project site consists of four parcels with a total area of 152 acres. BEP I construction has recently been completed on the original 76 acre site, parcels 34 and 35. BEP II would be constructed on the adjacent 76 acre extension site to the west, parcels 36 and 37.

The project would consist of a 520 MW combined cycle power plant, to be interconnected to the Buck Boulevard Substation in the northeast corner of the BEP I/BEP II site.

IMPACTS

According to Appendix G of the Guidelines to the California Environmental Quality Act (CEQA), a project may have a significant effect on land use if the project would:

- Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project adopted for the purpose of avoiding or mitigating an environmental effect;
- Disrupt or divide an established community;
- Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance, as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to a non-agricultural use;
- Conflict with existing zoning for agricultural use, or a Williamson Act contract; or
- Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to non-agricultural uses.

A project may also have a significant impact on land use if it will create unmitigated noise, dust, public health hazard or nuisance, traffic, or visual impacts, or when it precludes or unduly restricts existing or planned future uses.

CONFORMITY WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

Public Resources Code § 25525 states that the Energy Commission shall not certify any facility when it finds:

> …that the facility does not conform with any applicable state, local, or regional standards, ordinances, or laws, unless the [Energy] commission determines that such a facility is required for public convenience and necessity and that there are not more prudent and feasible means of achieving such public convenience and necessity. In making the determination, the commission shall consider the entire record of the proceeding, including, but not limited to the impacts of the facility on the environment, consumer benefits, and electric system reliability.
>
> In no event shall the Commission make any finding in conflict with applicable federal law or regulation.

When determining if a project is in conformance with State, local or regional ordinances or regulations, the Energy Commission typically meets and consults with applicable agencies to determine conformity and, when necessary, "to attempt to correct or eliminate any noncompliance" (§ 25523(d)(1)). The LORS and policies applicable to the project have been analyzed below to determine the extent to which BEP II is consistent with each requirement or standard.

State

Subdivision Map Act, 1972

BEP II would be located entirely within the BEP I site's expanded boundaries. The site is located in the eastern 1/2 of the NW1/4, Section 33, T6S, R22E. The site is comprised of four parcels. BEP I has been constructed on Parcels 34 and 35; a lot line adjustment was recorded with Parcel 34 to create a separate Parcel "B" for the Buck Substation. BEP II would be located on the expansion portion of the site, parcels 36 and 37 and may, or may not be owned by the same entity as BEP I. The BEP II facilities would occupy approximately 10.45 acres of the property excluding the evaporation ponds (BEP II 2003a, p. 27). Condition **LAND-6** would require that if necessary a lot line adjustment allowing for all project facilities except linear facilities on one parcel and confirmation of ownership of each site be completed before construction starts. If the project site plan recommended for approval by the City demonstrates that the required project facilities are located on one parcel and owned by one entity, **LAND-6** would not be included in the FSA.

Local

County

If the applicant's implementation of its WCOP includes the permanent retirement of irrigated lands, the WCOP could be inconsistent with the County General Plan policies in the Land Use Element and the Environmental Hazards and Resources Element related to preservation of agricultural land noted above. See the "Compatibility with Agriculture" section below for an explanation of this possible conflict and recommended conditions that would mitigate the impact of the WCOP.

City

City of Blythe General Plan

The City General Plan designates the BEP II site as Heavy Industrial (I-H). The project is consistent with this designation, and the City's goals for new additional industrial development.

The proposed project is generally compatible with land uses immediately adjacent to the site, which consist of an orchard on the east side and vacant land on the remaining areas. In general, the City's agricultural goals and policies encourage the continuation of agricultural use in the incorporated area. However, BEP II is potentially in conflict with these goals and policies if the proposed WCOP includes permanent retirement of irrigated land. In this case implementation of the WCOP would reduce prime farmland acreage, and without mitigation would be a significant impact. See the discussion on the WCOP below under "Compatibility with Existing and Planned Land Uses".

City of Blythe Zoning Regulations

The General Industrial Zone allows a variety of manufacturing uses by right including public maintenance services, utility operations facilities, custom manufacturing, general manufacturing, and warehousing in accordance with §17.08 010 of the City of Blythe Zoning Ordinance. The proposed power plant would be considered a Utility Operations Facility as defined in §17.08.710 of the City of Blythe Zoning Ordinance and allowed by right in the Heavy Industrial zone (Petritz 2002a). This zone, however, does contain a maximum height restriction of thirty-four (34) feet (§17.10.040 of the City of Blythe Zoning Ordinance). The heights of structures included in the design of the proposed power plant that may exceed the zoning district height limitations are listed below. Some of these structures may fall within the definitions included in City Zoning Ordinance Par. 17.10.041, "Commercial broadcast antennas, communications towers and microwave masts", and would be within the maximum height identified in this paragraph of 109 feet (Petritz 2002b).

Generation Building	60 feet
Heat Recovery Steam Generator (HRSG) Stack	130 feet
Heat Recovery Steam Generator	93 feet
Cooling Tower	40 feet
Raw Water Supply Tank	43 feet
Demineralized Water Storage Tank	43 feet
Brine Concentrator	98 feet
Transmission Lines	95 feet (or 145 feet if double-circuited)

The City has indicated that an advisory recommendation regarding the project siteplan and the height variance would be provided to the CEC after submittal of site plan and variance applications by the project applicant to the City (Wellman). The City Project Review Committee has reviewed the project, but the applicant has not yet filed applications with the City for the site plan and height variance (Wellman). Staff has sent the City a written request for this recommendation. The site development plan must comply with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance. The site development plan must contain the following features:

a. Setbacks (i.e. yard area requirements) for structures;

b. Building elevations;

c. Temporary and permanent signs for project identification (permanent and construction phase signs);

d. Permanent parking lot design, showing the quantity and dimension of spaces;

e. Parcel lot lines; and

f. Landscaping

See the Visual Resources Section of this PSA for a discussion of landscaping requirements.

LAND-1 would require that the applicant submit evidence of City review during project construction demonstrating compliance with the approved site plan. . **LAND-2** would require that the applicant submit to the City of Blythe descriptions of the final laydown/staging areas for the City's review and comment.

Blythe Airport Comprehensive Land Use Plan

As described in the *CLUP,* five safety zones are defined around airports to promote the safety of persons on the ground while reducing risks of serious harm to crews and passengers of aircraft making forced landings in the immediate environs of the airport. The CLUP provides land use compatibility guidelines that apply to each of these zones. These zones are the: Inner Safety Zone (ISZ);

- Outer Safety Zone (OSZ;);
- Emergency Touchdown Zone (ETZ);
- Traffic Pattern Zone (TPZ); and the
- Extended Runway Centerline (ERC).

As shown in **LAND USE FIGURE 4, Blythe Airport Safety Zones**, the 152-acre power plant site is within four of these safety zones: the OSZ, the ETZ, the TPZ, and the ERC. The BEP II project structures within the site, which would occupy approximately 10 acres, are entirely in the TPZ. The adjacent, existing BEP structures also occupy about 10 acres, which are within the ERC and TPZ zones. The CLUP's descriptions and land use compatibility guidelines for these latter four zones and the ISZ are as follows (Coffman, pp. 3-4 - 3-6):

- The ISZ is an area immediately off the runway end, 1,500 feet wide and from 1,320 to 2,500 feet long, depending on the type of runway approach and the type of aircraft using the runway. An area of significant accident risk, no structures should be permitted in this zone.

- The OSZ is an area along the ERC immediately beyond the ISZ, which is 1,500 feet wide and ranges from 2,180 to 2,500 feet long. Structures should not cover more than 25% of the lot. The OSZ should contain no public utility stations or plants, and no uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials.

- The ETZ is a 500-foot wide area extending from the primary surface of the airport runway to the end of the OSZ and is intended as an emergency landing area. This area has the greatest accident risk, so no structures or significant obstructions should be permitted.

- The TPZ is the area around the airport that is most frequently flown over by aircraft and within which the local traffic pattern is located. This zone extends approximately 10,000 feet off the ends and sides of runways. Structures should occupy no more than 50 percent of the gross development area or 65 percent of the net lot area, whichever is greater. There should be no uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials."

- The ERC is 1,000 feet wide and extends 5,000 feet off of the end of the OSZ. Structures should occupy no more than 50 percent of the gross development area or 65 percent of the net lot area, whichever is greater. There should be no land uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials.

The CLUP states that any uses posing the following risks to aircraft in flight shall be prohibited within all safety zones (Coffman, p. 7-6):

- light and reflection interference;
- smoke, or water vapor;
- gathering of birds; and
- electrical interference.

The CLUP includes from the State Airport Land Use Planning Handbook (Caltrans, 1983, p. 101) detailed descriptions of these risks, including any use "…which may otherwise affect safe air navigation within this area." (Coffman, p. 3-7)

Regarding these risks, the CLUP states (Coffman, p. 7-6):

- Only a few kinds of land uses have inherent attributes that would make them necessarily violate these standards. (Landfills and power generating plants are examples.)

The CLUP did not elaborate on the inherent attributes which cause power plants to trigger these risks and/or standard violations. Staff is seeking clarification of the above CLUP paragraph from the various entities involved in airport land use planning (i.e., the ALUC, and the Caltrans Division of Aeronautics and its consultant).

The key power plant structures would occupy approximately 10.45 acres of the 76 acre expansion site (BEP II 2003a, p. 27). Thus, structures would occupy less than 50 percent of the gross lot area of the site and the project is consistent with the development area provisions of the safety zones.

The applicant states that all project features located in the safety zones are consistent with the CLUP (BEP II 2002b, p. Land-6). However, on July 18, 2002, the ALUC made an advisory determination that the project would be inconsistent with the CLUP (ALUC 2002a). The ALUC staff report for the project considered a number of issues related to land use in making its recommendation of inconsistency including the project's capacity to attract wildlife, the need for legal easements and project signs, lighting, sun reflection, smoke and water vapor generation, and electrical interference. The staff report noted the inherent incompatibility of power plants with the Blythe Airport if located in any of the safety zones (ALUC 2002b, p. 2).

However, the ALUC staff report does not note as a safety issue the possibility of danger to air traffic from thermal plumes generated by the project, which is discussed in detail in the Traffic and Transportation section of this PSA. In the case of BEP II, pursuant to the Warren-Alquist Act the Energy Commission is the permitting agency and has the jurisdiction to concur with or overrule the ALUC's determination. If the Energy Commission overrules this determination and decides to certify this project, the ALUC has recommended mitigating conditions (ALUC 2002a). However, ALUC staff has stated that even with the implementation of the conditions, the project would still be inconsistent with the CLUP (Downs). The City of Blythe, which has a contract with Riverside County to operate the Airport, has not yet made a recommendation to the Commission regarding the ALUC's determination, and has not set a schedule to make this recommendation (Wellman). Staff has sent a letter to the City requesting the City's submittal of its analysis and recommendation of the ALUC's determination. Although staff concurs with the ALUC that the project is in violation of the CLUP, given the CLUP's inclusion of power plants as having inherent attributes that violate safety standards, the safety issues noted by the ALUC staff report could be adequately mitigated through implementation of the conditions included in this PSA. However, the issue of thermal plumes, not included in the ALUC's staff report, would fall under the CLUP's admonition against any use "… which may otherwise affect safe air navigation…."

The thermal and visual plume studies discussed in the Traffic and Transportation section of this PSA must be completed before staff can reach conclusions on the project's conformity with the CLUP and compatibility with airport operations. Condition **LAND-5** would require the applicant to comply with the ALUC's proposed conditions relevant to land use.

The CLUP also contains airport vicinity height guidelines. These guidelines are based on standards developed by the FAA for determining obstructions in the navigable airspace (See the **TRAFFIC AND TRANSPORTATION** section of the PSA). The proposed BEP II site is located below the FAA Horizontal Surface, which covers generally the same area as the TPZ. The boundaries of the Horizontal Surface are set at a radius of 10,000 feet from Runway 8-26. The elevation of the Horizontal Surface height limitation is 150 feet above the airport elevation, at an elevation of 547 feet mean sea level (MSL) (Coffman, p. 6-2).Refer to the **TRAFFIC AND TRANSPORTATION, VISUAL RESOURCES,** and **PUBLIC HEALTH** sections of this PSA for other conditions related to the ALUC recommendations.

Additional details regarding potential impacts on Airport operations are provided in the **TRAFFIC AND TRANSPORTATION** section of thePSA.

COMPATIBILITY WITH EXISTING AND PLANNED LAND USES

Power Plant Site

The proposed power plant**,** located in a largely nonurbanized area, will not physically divide an established community.

Compatibility with Airport Operations

BEP II would be located approximately one mile from the end of Blythe Airport's primary runway. A local pilot and aviation business owner has recently raised concerns regarding the hazards to aircraft using Blythe Airport. His concerns focus on potential hazards caused by thermal and water vapor plumes from both the existing BEP I and proposed BEP II power plants (Wolfe 2003a, & 2003b). The BEP I owners have stated that the thermal and visual plumes caused by BEP I and II will not have an impact on aviation safety (BEP 2003). However, ALUC staff has stated that the effect of visual and thermal plumes could be a danger (Downs). The Energy Commission staff has asked the FAA and the Caltrans Aeronautics Division to review the BEP II's proposed site plan in light of these plume-related aviation safety concerns. The LAND USE Section of the BEP II FSA cannot be completed until there is sufficient information to allow a thorough analysis of the impact of BEP II on airport traffic safety. This information would include studies assessing the impact of visual and thermal plumes.

Compatibility with Agriculture

The proposed project would be compatible with nearby agricultural uses. The proposed project would not be sensitive to agricultural practices and would not restrict normal operations on the adjacent lemon orchard. With the implementation of the conditions of certification contained in the **AIR QUALITY** section of the PSA that require control of fugitive dust, the project's construction activities would not adversely affect agricultural crops in the area.

The BEP II site is classified as Farmland of Local Importance. The Farmland of Local Importance designation is applied where soil types would qualify as prime farmland if the land were irrigated.

Staff has reviewed BEP II's proposed Water Conservation Offset Program (WCOP), which could indirectly affect local agriculture. The WCOP is discussed below.

Water Conservation Offset Program

The applicant has stated its intent to implement a voluntary WCOP in exchange for project water use, although not required by any LORS. The WCOP as described by the applicant (BEP II 2002a, p. 7.2-6) proposes to retire irrigated lands permanently or fallow lands on a rotating basis to reduce demand for agricultural irrigation. Acquisition of lands and/or irrigation rights would be accomplished through purchase or lease by BEP II. The WCOP would include the permanent retirement or rotational fallowing of lands within Palo Verde Irrigation District (PVID) boundaries on the Mesa or the Palo Verde Valley (BEP II 2002a, p. 7.13-3). If the land retirement option is chosen, the applicant has stated that the land to be retired would not result in a Williamson Act contract[4] violation (BEP II 2003b, pp. 12-13). An estimated total of up to 786 acres would be retired (BEP II 2002a, p. 7.2-6) based on an assumed consumptive water use rate of 4.2 acre-feet per acre (BEP II 2002a, p. 7.13-3). This equates to approximately

[4] The California Land Conservation Act, also known as the Williamson Act, allows owners of agricultural land to have their properties assessed for tax purposes on the basis of agricultural production rather than the current market value in exchange for contractual acceptance of restriction of use to agricultural and compatible uses. Individual counties and cities administer this program. Contracts run for 10 to 20 years, depending on the administering entity.

0.7 percent of total irrigated farmland in the PVID. If the WCOP utilizes full or partial rotational fallowing, the amount of land in the WCOP could be greater in order to allow for the necessary transition of acreage at any one time. A map of the lands under consideration for retirement or rotational fallowing on the Mesa or in the Valley is to be included in a confidential filing by the applicant.

Much of the lands on the Mesa that are in agricultural production are citrus orchards. Citrus represents one of the highest value crops in the area (7.43 percent of the total 2001 value) but represents only 2.53 percent of the total 2001 acreage in the Palo Verde Valley agriculture district. The investment required to get a citrus orchard to the production stage is substantial (Rethswitch). Retirement of currently active citrus producing lands could be a substantial economic impact to agriculture in the area. Citrus crops are among the highest value crops in the area, comprising approximately 3 percent of the harvested acreage in the agricultural district but contributing approximately 7 percent to the gross crop value (See Agricultural Commissioner reference for acreage and value summary).

Because specific lands have not been identified, it is not known if this program would have a significant adverse impact on Prime Farmland or Farmland of Statewide Importance[5], as shown on the Department of Conservation (DOC) Important Farmland Map for eastern Riverside County. Similarly, the potential impact on any Williamson Act contract lands is unknown at this time. The applicant has stated that Prime Farmlands, Farmlands of Statewide Importance, and lands included in a Williamson Act Preserve would not be included in the WCOP (BEP II 2002a, p. 7.2-8). However, if this were to be the case, staff is unclear as to how the WCOP would conserve water, since irrigated farmland in the Palo Verde valley area is typically classified as the above Important Farmland Map categories, and is often under Williamson Act contract. If the WCOP is part of the project, staff cannot complete the FSA until the applicant resolves this inconsistency. The Riverside County Planning Department administers the Williamson Act Land Conservation Program. Because the WCOP would potentially cause a significant impact on agricultural land and could conflict with the Williamson Act Preserve Program, the project could have a potentially significant impact on agriculture.[6]

LAND-3 would assure that the WCOP would not conflict with the Williamson Act Program**. LAND-4** would assure the mitigation of the loss of farm land caused by the WCOP.

See the Soil and Water section of this PSA for further discussion of the WCOP.

CUMULATIVE IMPACTS

Water Conservation Offset Program

The applicant considers the WCOP to be voluntary; however, the applicant would not implement the WCOP if BEP II is not developed. In general, loss of productive, irrigated

[5] Farmland of Statewide Importance is similar to Prime Farmland but with minor shortcomings, such as greater slope or less capacity to hold and store moisture. Lands of Statewide Importance must have been in production of irrigated crops at some time during the update cycles prior to the mapping date.

agricultural lands is considered a significant cumulative impact. While the WCOP's 786 acres of irrigated agricultural lands represent only 0.7 percent of the total irrigated lands in the Palo Verde Valley agricultural district, loss of agricultural land is a regional and statewide concern. Loss of agricultural production is an incremental process, which eventually has an effect on the ability of a region to sustain agriculture and the agriculturally related service economy.

Imperial Irrigation District Transmission Line

The Imperial Irrigation District (IID) has proposed to construct a new 118-mile transmission line from Buck Boulevard substation on the BEP I/BEP II site to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs. BEP II would connect with The Buck Boulevard Substation, which would connect with the IID transmission line. The IID's Proposed Project also include a new substation/switching stations on Hobsonway to the west of the BEP I site and on Dillon Road adjacent to the existing transmission line facilities near Indio (BLM/IID p. ES-8).

IID's Proposed Project would be located entirely in a BLM-designated corridor (BLM/IID p. 3.7-16). The project area is generally rural desert land with large amounts of undeveloped open space areas. The Proposed Project and two other alternatives travel through or are adjacent to seven incorporated cities and several unincorporated communities in Riverside County (BLM/IID p. 3.7-3). It is not clear from available documentation how many residential units and commercial buildings, and the amount of residentially and commercially-zoned vacant property, would be impacted by the IID project. Therefore it is possible that the IID project could have a significant impact on residential and commercial units and vacant property. However, because BEP II does not have an impact on residential or commercial units and vacant property, any such impact by the IID project would not be a cumulative impact in combination with BEP II.

Portions of the IID's Proposed Project and all other alternatives would travel through irrigated, productive farming areas. However, the available documentation does not specify the amount of Prime and other Important Farmland that would be affected (see BLM/IID pp. 3.7-32 – 3.7-39). Prime and other Important Farmlands impacted by the project would be spanned by support structure footprints where feasible (BLM/IID p. 3.7-35). It is not clear from available documentation how much Prime and other Important Farmland would be impacted by the project when spanning is not feasible. Furthermore, there is no documentation regarding the amount of prime and important farmlands impacted by the footprint of the project support structures. Staff assumes that agricultural land covered by support structure footprints and an unknown amount of land around each support structure would be impacted. Staff does not have sufficient information to determine that the IID project would not have a significant impact on prime and important farmland. However, if **LAND-3** and **4** are implemented, BEP II's impact on agricultural land would be completely offset. Therefore, the project would not contribute to any potential cumulative impact on agricultural land.

The second major IID project alternative and its minor alternative, labeled options B and B-1, may require an amendment to the BLM's California Desert Conservation Area Plan because these alternatives would not be located entirely within a BLM-designated utility corridor. A general plan amendment and zoning variance from Imperial County would be required for alternatives B and B-1 because the transmission line structures would exceed height limitations. Alternatives B and B-1 may require a consistency review by the Imperial County ALUC. These LORS considerations for the IID project do not constitute a cumulative impact in combination with BEP II, which is entirely within the City of Blythe.

BLYTHE ENERGY PLANT PHASE ONE

As discussed above under Compatibility with Existing and Planned Land Uses, concerns regarding the impact of BEP I and BEP II visual water vapor plumes and thermal plumes on air traffic safety are unresolved. It is possible that the combined impact of visual and thermal plumes from the two plants would create a cumulative effect on air traffic safety that would be greater than the separate impact of the plumes from each plant (Downs). This issue must be resolved before the Land Use FSA can be completed. The visual and thermal plume studies discussed above would have to include analysis of the cumulative effects of the two plants. At this time with present information staff concludes that there is a possible cumulative impact caused by the combined effect of visual water vapor and thermal plumes from BEP I and BEP II.

GROWTH INDUCING IMPACTS

The region in which the BEP II site is located is sparsely populated and exhibits fairly low growth potential compared to the rest of Riverside County. There is continued potential for tourist trade and recreation/destination traffic associated with the Colorado River; active freight rail service, and possible expansion of the Blythe Airport.

In general, power plants do not, in and of themselves, induce growth in the area where they are built. In the case of BEP II, the project may: 1) displace imported electricity, thereby not resulting in any additional electricity or growth effects in Blythe, and /or 2) send any surplus electricity outside of Blythe if there is not enough demand within Blythe. In the second instance, it is impossible to predict where the electricity will go. Therefore, an analysis of the potential for regional growth inducement would be speculative.

Under CEQA, staff need not analyze the growth-inducing effects of a project if that project is already analyzed in local planning documents, and if those documents also discuss growth targets and limits. [City of Carmel-by-the-Sea v. U.S. Dept. of Transportation 123 F.3d 1142 (9th Cir. 1997)].

The project as a whole is consistent with the City of Blythe General Plan (General Plan), for which a Final Environmental Impact Report (FEIR) has been certified. The FEIR analyzes the growth in population, jobs and housing that would be attributable to a build-out of the City of Blythe. The General Plan proposes, and the FEIR analyzes 181 acres as having Heavy Industrial development potential (Blythe 1989). Since BEP II would be an industrial use within the plan area and conforms to the General Plan’s Heavy Industrial designation, any growth-inducing impacts associated with BEP II as part of the industrial build-out have been analyzed by the General Plan. Staff does not foresee any growth-inducing impacts specifically from BEP II that go beyond what has already been discussed in the General Plan or FEIR.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and the low-income population is less than fifty percent within the same radius. Based on the land use analysis, staff has identified unmitigated significant direct and cumulative impacts resulting from the operation of the project that could affect the safety of air traffic. However, staff has no data demonstrating that potentially affected air traffic employees and clientele would be greater than fifty percent people of color, or that the minority population would be disproportionately impacted. and Therefore there are no land use environmental justice issues related to this project.

FACILITY CLOSURE

At some point in the future, the proposed facility would cease operation and close down. At that time, it would be necessary to ensure that closure occurs in such a way that public health and safety and the environment are protected from adverse impacts.

Closure of a facility like BEP II can be temporary or permanent. Temporary closure is defined as a shutdown for a period exceeding the time required for normal maintenance, including for overhaul or replacement of the combustion turbines. Causes for temporary closure include a disruption in the supply of natural gas or damage to the plant from earthquake, fire, storm, or other natural acts. Permanent closure is defined as a cessation in operation with no intent to restart operations because of plant age, damage to the plant beyond repair, economic conditions, or other reasons.

For a temporary closure where there is no release of hazardous materials, security of the facility will be maintained on a 24-hour basis, and the Energy Commission and other responsible agencies will be notified. Depending on the length of shutdown necessary, a contingency plan for the temporary cessation of operations will be implemented.

The planned lifetime of BEP II is estimated at 30 years. However, if the generation facility were still economically viable, it could be operated longer. It is also possible that the facility could become economically noncompetitive earlier than 30 years, forcing early decommissioning. Whenever the facility is to be closed permanently, the closure procedure will follow a plan that is subject to Energy Commission review and approval.

At least twelve months prior to the initiation of decommissioning, the Applicant would prepare a Facility Closure Plan for Energy Commission review and approval. This review and approval process would be public and allow participation by interested parties and other regulatory agencies. At the time of closure, all applicable LORS would be identified and the closure plan would discuss conformance of decommissioning, restoration, and remediation activities with these LORS. All of these activities would fall under the authority of the Energy Commission.

There are at least two other circumstances under which a facility closure can occur: unexpected temporary closure and unexpected permanent closure. At the time of permanent closure, all applicable LORS would be identified and the closure plan would discuss conformance of decommissioning activities with these LORS.

The information provided in the AFC did not specifically address the effects of project closure on land use issues and concerns. Staff has not identified any LORS from a land use perspective that the applicant would have to comply with in the event of unexpected temporary closure or unexpected permanent closure of BEP II.

CONCLUSIONS AND RECOMMENDATIONS

1. The WCOP has the potential to cause significant adverse impacts to agricultural resources in the area and therefore could be in conflict with County and City goals and policies that encourage retention of agricultural land. The WCOP would affect agricultural land or land that can be used for agriculture, either on the Mesa or in the Palo Verde Valley. The major land use concerns with the WCOP are that:

   a) it could have an adverse impact on agriculture by retiring irrigated farm lands especially with productive citrus orchards or other high value crops; and

   b) the fallowing program could conflict with Williamson Act contracts.

   c) the applicant’s description of the WCOP appears to exclude all types of irrigated lands that could be included in the WCOP. Given this inconsistency staff cannot determine the impact.

   Staff recommends that:

   ∉ any permanent retirement of productive farmland by the WCOP be mitigated;

   ∉ in order to avoid impacts to lands under Williamson Act contract, the applicant obtain the Riverside County Agriculture Commissioner's and County Planning Department’s review of WCOP-proposed parcels for any Williamson Act contract conflicts; and

   ∉ the applicant should submit a revised WCOP description clarifying what classifications of irrigated farmland would be included in the WCOP.

   Before the Land Use section of the FSA can be completed, the applicant must determine whether the WCOP would permanently transfer irrigation water to non-agricultural use resulting in retirement of agricultural land ; and submit the classifications and Williamson Act status of farmland that would be included in the WCOP.

2. The project is consistent with the City’s General Plan and generally consistent with the City’s zoning. However, the project would exceed the City’s 34-foot height restriction in the Heavy Industrial Zone. Ordinarily the City would require a variance to allow a structure height in excess of the height limit. The applicant has not yet applied to the City for site plan approval and a height variance. If the City

recommends approval of the variance, the nonconformance with City LORS would be resolved.

3. The ALUC has determined that the project is inconsistent with the CLUP, while recommending conditions if the Energy Commission decides to approve the project. The City has not yet submitted its analysis and recommendation to the CEC regarding the ALUC's determination. Because the City Council for the City of Blythe could overrule the ALUC by a two-third's majority vote if the City were the CEQA lead agency, staff has requested in writing the City's analysis and recommendation regarding the ALUC's determination of inconsistency. The potential for land use compatibility impacts, including cumulative impact, of visual water vapor plumes and thermal plumes caused by the project are unknown.

   Staff cannot reach a conclusion regarding the consistency of the project with the CLUP, and cannot complete the Land Use Section of the FSA until there is sufficient information to allow a thorough analysisof the impact of BEP II on airport traffic safety. This analysis would be based on studies of the potential impact of visual and thermal plumes on airport operations. These studies would include assessment of the cumulative impact of BEP I and BEP II.

   The proposed conditions of certification are recommended so that any significant impacts by the project would be mitigated to the extent feasible; upon review of the City of Blythe's recommendation on the ALUC's determination and review of the analysis of visual and thermal plume concerns, staff may recommend further conditions in the FSA.

PROPOSED CONDITIONS OF CERTIFICATION

If the Energy Commission certifies BEP II, staff recommends that the Commission adopt the following proposed conditions of certification:

LAND-1 The project owner shall prepare a site development plan that complies with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance. The site development plan must contain the following features:

- Setbacks (i.e. yard area requirements) for structures;
- Building elevations;
- Landscaping requirements;
- Temporary and permanent signs for project identification; permanent and construction phase signs);and
- Permanent parking lot design, showing the quantity and dimension of spaces.

Following preparation of the above site development plan, the project owner shall design and construct the project consistent with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance.

<u>Verification:</u> At least 60 days prior to the start of construction, the project owner shall concurrently submit the site development plan to the CPM and the City of Blythe. The material submitted to the CPM must include documentation that the City of Blythe has been given the opportunity to review and comment on the plan and its compliance or conformance the above-referenced requirements.

Monthly Compliance Reports submitted to the CPM must contain a written statement from the CBO that the project is being constructed in compliance with the site development plan.

LAND-2 The project owner shall provide descriptions of the final laydown/staging areas identified for project construction to the Director of the City of Blythe Development Services Department for review and comment, and the CPM for review and approval. The description shall include:

(a) Assessor's Parcel numbers;
(b) addresses;
(c) land use designations;
(d) zoning;
(e) site plan showing dimensions;
(f) owner's name and address (if leased); and,
(g) duration of lease (if leased); and, if a discretionary permit was required; (2) copies of all discretionary and/or administrative permits necessary for site use as laydown/staging areas.

<u>Verification:</u> The project owner shall provide the specified documents to the CPM at least 30 days prior to the start of any ground disturbance activities. [1/18/02]

LAND-3 The proposed Water Conservation Offset Program (WCOP) shall not include retirement or rotational fallowing of farmlands which violate any provision of a Williamson Act Contract.

<u>Verification:</u> At least 60 days prior to implementation of the WCOP, the project owner shall submit detailed information to the CPM regarding the Williamson Act Preserve and contract status of the parcels involved in the WCOP. If the program will fallow or retire any parcels under Williamson Act contract, the project owner shall provide documentation that such fallowing or retirement has been reviewed and approved by the Riverside County Agricultural Commissioner and the Riverside County Planning Department, and does not violate any provision of a Williamson Act contract. Any WCOP agreements that are altered or added to the program shall be submitted with the above documentation to the CPM at least 30 days prior to taking effect.

LAND-4 If the WCOP involves permanent transfer of irrigation water previously used for productive irrigated farmland, the project owner shall mitigate at a one-to-one acre ratio for the conversion of productive farmland in the fulfillment of the WCOP through permanent retirement (time of the expected life of the project or greater) by implementing one or more of the following strategies:

1) a mitigation fee payment to a City of Blythe or Riverside County agricultural land trust or the American Farmland Trust consistent with a prepared Farmlands Mitigation Agreement. The payment amount shall be determined by contacting the local assessor's office to determine the assessed value for the acreage of productive agricultural land retired by the WCOP, or by a real estate appraiser selected by the project owner and approved by the CPM.

2) securing the acquisition of an agricultural easement for other farmland in the vicinity. Easements for irrigated farmland would be acquired based on the California Department of Conservation's Important Farmland Classification Map, but in no case shall be less than a 1:1 ratio.

<u>Verification:</u> Thirty (30) days prior to start of construction, the project owner shall provide in its monthly compliance reports a discussion of any land and/or easements purchased in the preceding month by the trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be farmed in perpetuity. This discussion must include the schedule for purchasing the same acreage of productive farmland as retired by the WCOP and/or easements within one year of start of construction as compensation for the acreage of productive farmland to be converted by the WCOP.

LAND-5 The project owner shall comply with the following Riverside County Airport Land Use Commission conditions related to land use:

a) Conveyance of an avigation easement to the Blythe Airport for all portions of the project including offsite power lines and pipelines within the Airport Influence Area.
b) Approval of project signs by the City of Blythe.
c) Documentation that the Project will not generate smoke or water vapor which would attract large concentrations of birds, or which may otherwise affect safe air navigation within the area.

<u>Verification:</u> At least 60 days prior to the start of construction of the power plant or any other facilities associated with the project, the project owner shall submit to the CPM:

a) a copy of the avigation easement showing proof of recordation with the Riverside County Recorder;

b) documentation of approval of project signs by the City of Blythe;

c) documentation that the Project will not generate smoke or water vapor which would attract large concentrations of birds, or which may otherwise affect safe air navigation within the area.

LAND-6 The project owner shall obtain the necessary approval(s) from the City and complete any lot merger or lot line adjustments necessary to ensure that the proposed project, including associated facilities and improvements, but excluding linear facilities, will be located on a single legal lot and owned by one entity. That single lot shall include sufficient buffer areas to protect the health and safety of current or future occupants of adjacent lots. It shall remain a single lot for the life of the power plant.

Verification: At least 30 days prior to the start of construction, the Project Owner shall provide the CPM with proof of completion of the above adjustments or satisfactory evidence that no such adjustments are necessary. Prior to submitting an application to the City, the project owner shall submit the proposed lot configuration to the CPM for review and approval.

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Agricultural Commissioner's Office, Riverside County. Palo Verde Valley Acreage and Agricultural Crop Report. 2001.

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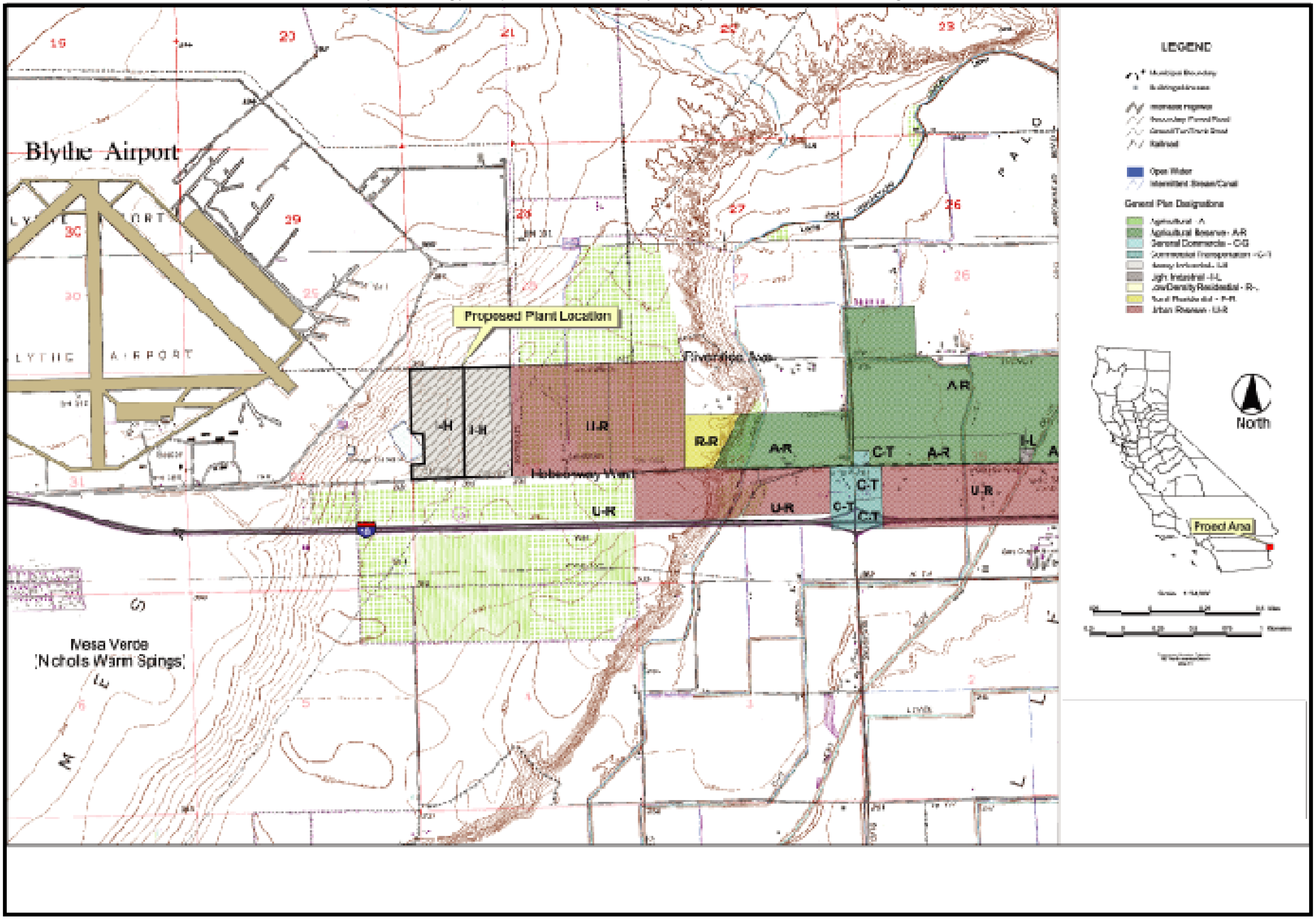
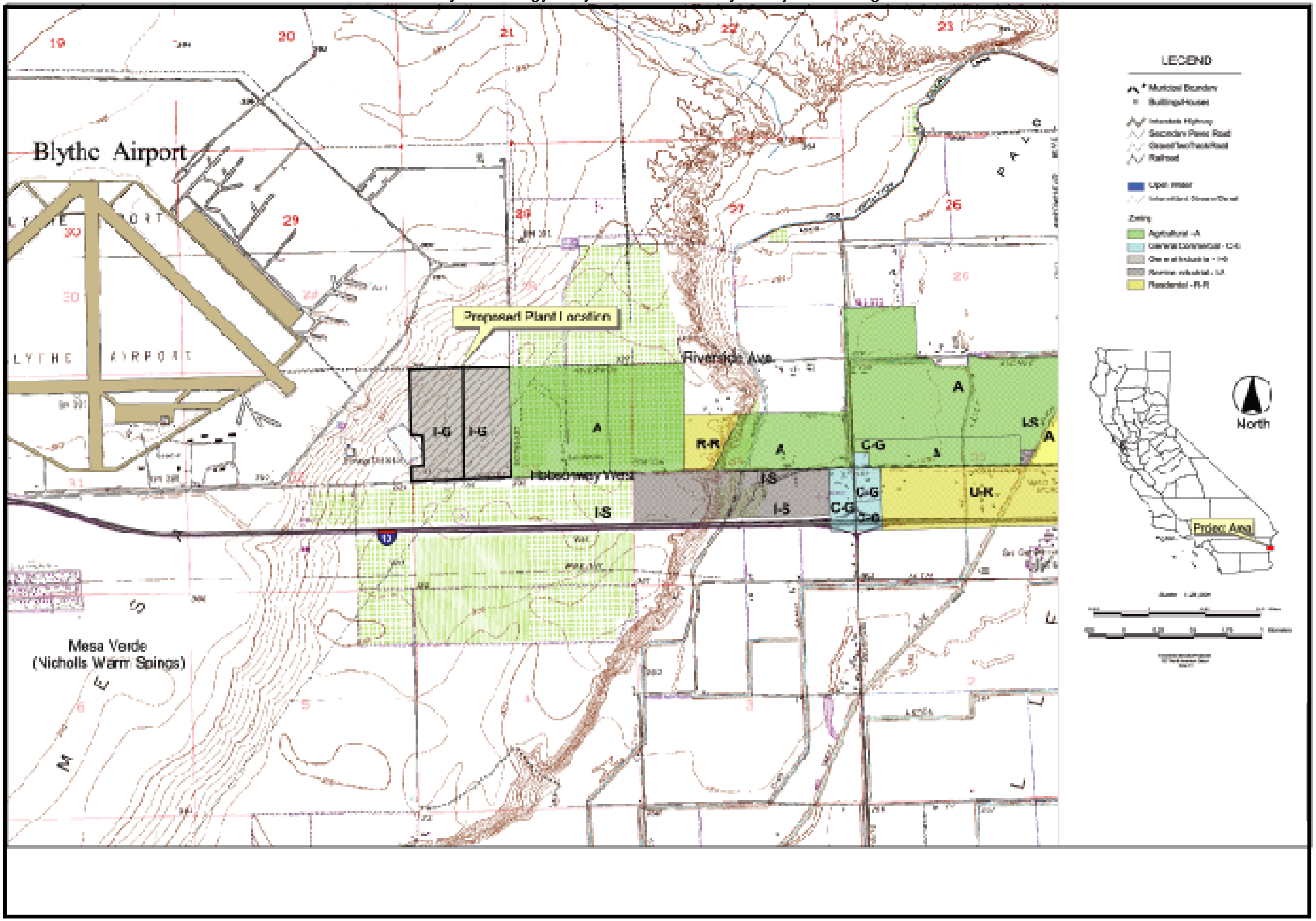
LAND USE - FIGURE 1

Blythe Energy Project Phase II - City of Blythe General Plan Designations



SOURCE: BEP II 2002a, Figure 7.2-1

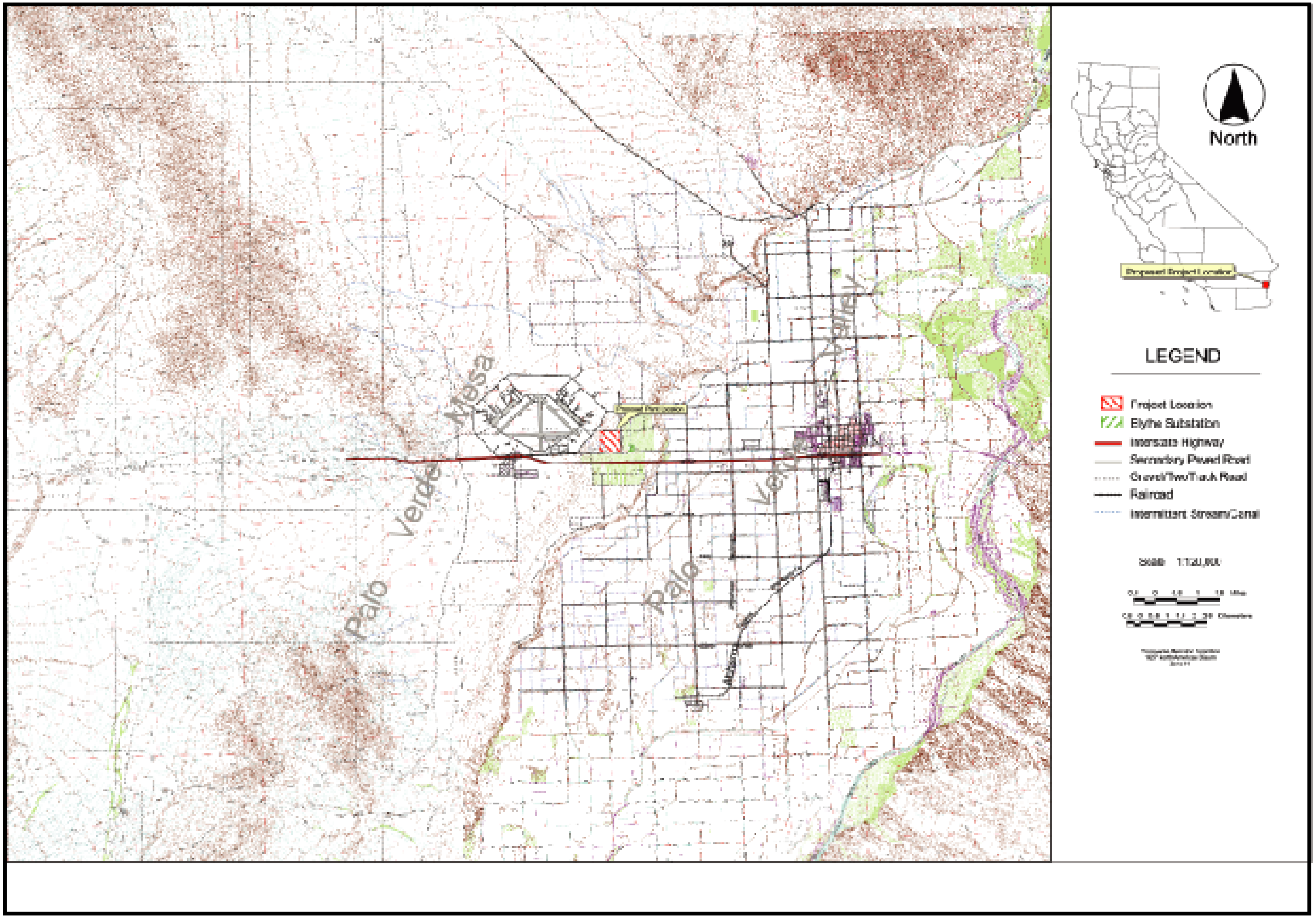
LAND USE - FIGURE 2
Blythe Energy Project Phase II - City of Blythe Zoning



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, AUGUST 2003
SOURCE: BEP II 2002a, Figure 7.2-2

LAND USE - FIGURE 3

Blythe Energy Project Phase II - Regional Location of the Proposed Project

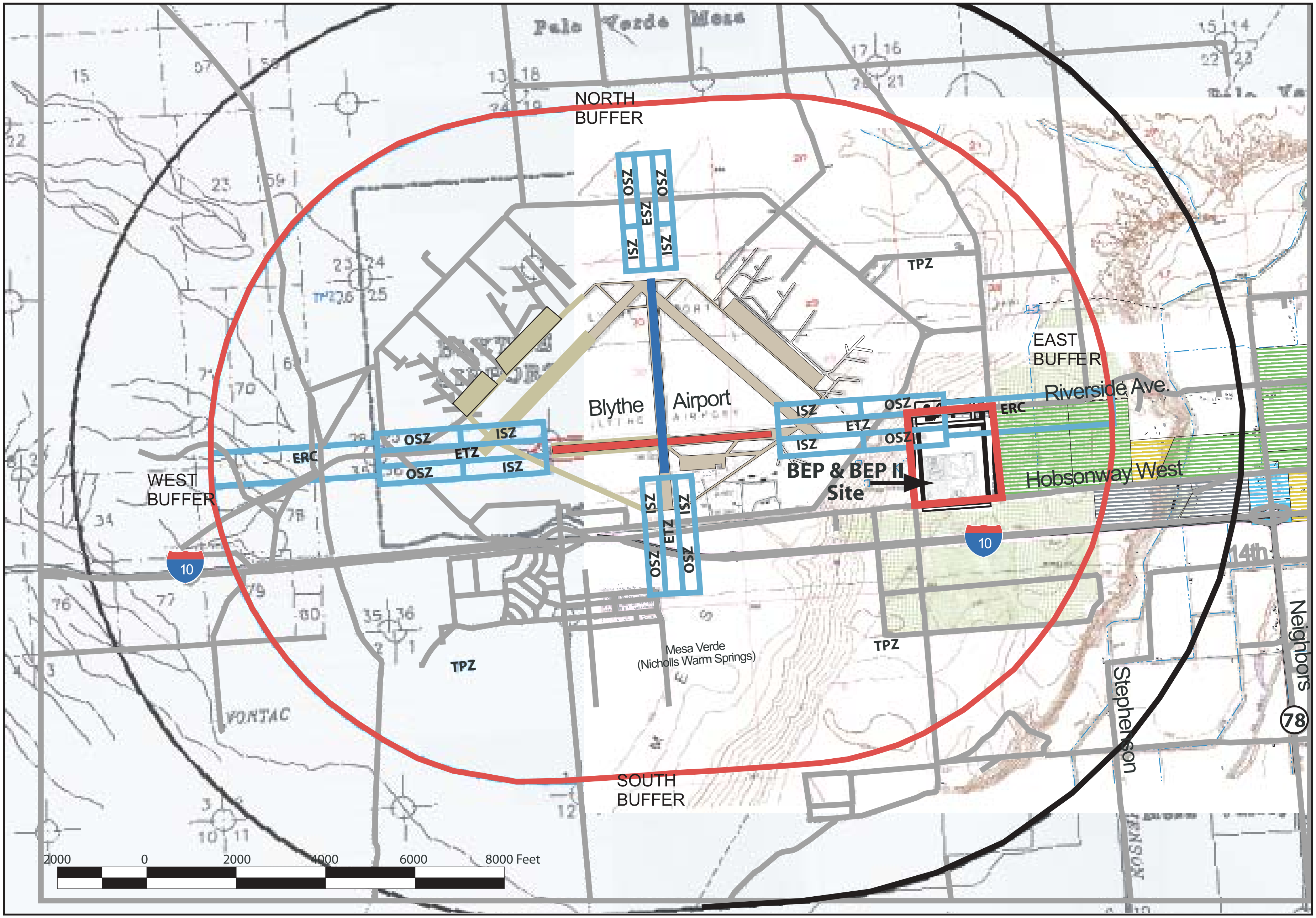


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: BEP II 2002a, Figure 2.0-1

LAND USE - FIGURE 4

Blythe Energy Project Phase II - Blythe Airport Safety Zones



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCES: BEP II 2002a - Figure 7.2-2, BEP II 2002b - Figure 36-1, Coffman - Exhibit 7a

NOISE AND VIBRATION

Testimony of Jim Buntin

INTRODUCTION

The construction and operation of any power plant creates noise or unwanted sound. The character and loudness of this noise, the times of day or night that it is produced, and the proximity of the facility to sensitive receptors combine to determine whether the facility would meet applicable noise control laws and ordinances, and whether it would cause significant adverse environmental impacts. In some cases, vibration may be produced as a result of power plant construction practices, such as pile driving. The ground-borne energy of vibration has the potential to cause structural damage and annoyance.

The purpose of this analysis is to identify and examine the likely noise and vibration impacts from the construction and operation of the Blythe Energy Project Phase II (BEP II), and to recommend procedures to ensure that the resulting noise and vibration impacts would be adequately mitigated, and would comply with applicable laws, ordinances, regulations, and standards (LORS).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

FEDERAL

Under the Occupational Safety and Health Act of 1970 (OSHA) (29 U.S.C. § 651 et seq.), the Department of Labor, Occupational Safety and Health Administration (OSHA) has adopted regulations (29 C.F.R. § 1910.95) designed to protect workers against the effects of occupational noise exposure. These regulations list permissible noise exposure levels as a function of the amount of time to which the worker is exposed (see **Noise Appendix A, Table A4** immediately following this section). The regulations further specify a hearing conservation program that involves monitoring the noise to which workers are exposed, assuring that workers are made aware of overexposure to noise, and periodically testing the workers' hearing to detect any degradation.

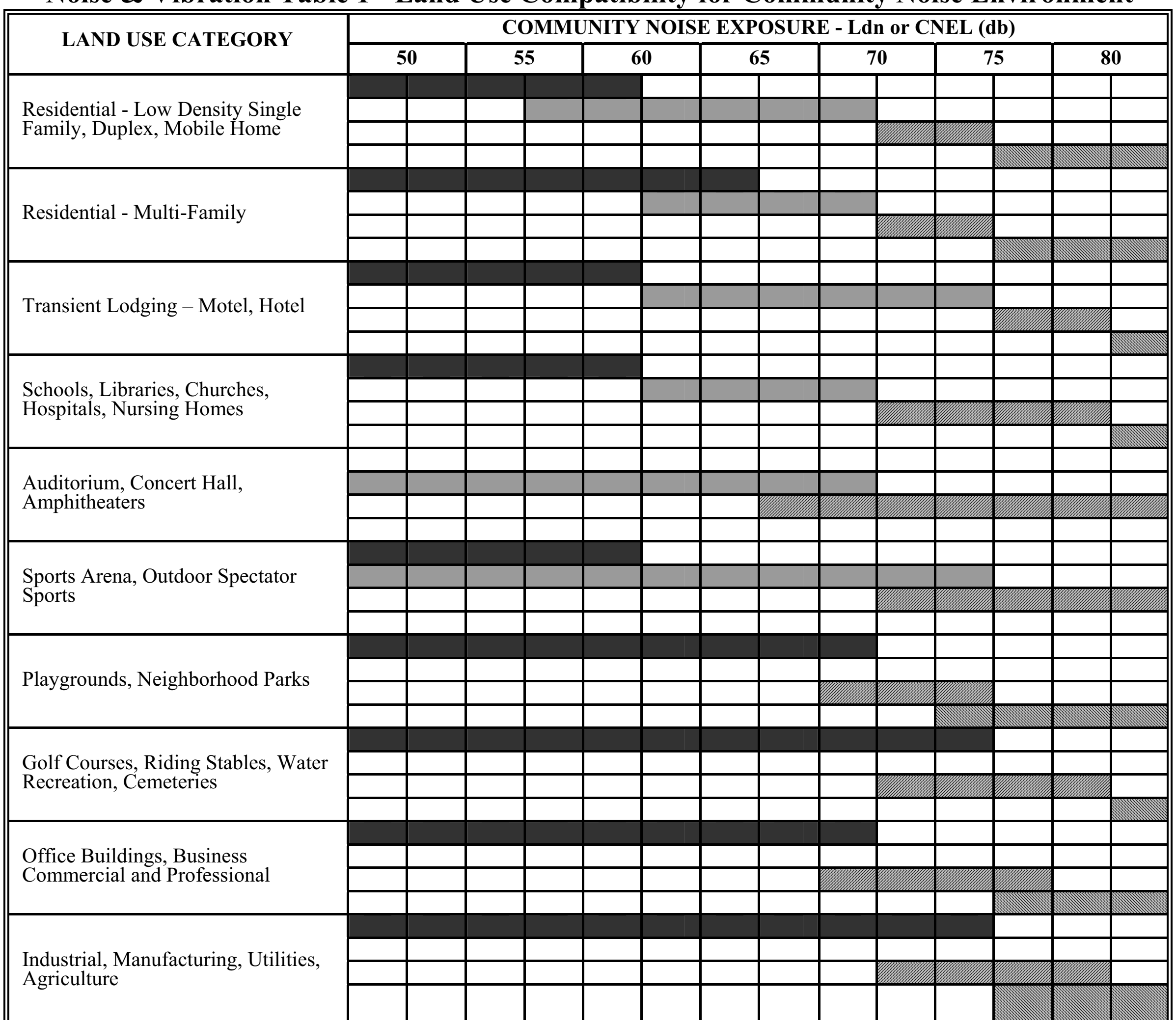
There are no federal laws governing off-site (community) noise.

The Federal Transit Administration (FTA) has published guidelines for assessing the impacts of ground-borne vibration associated with construction of rail projects, which have been applied by other jurisdictions to other types of projects. The FTA-recommended vibration standards are expressed in terms of the "vibration level," which is calculated from the peak particle velocity measured from ground-borne vibration. The FTA measure of the threshold of vibration perception is 65 decibels (VdB), which correlates to a peak particle velocity of about 0.002 inches per second (in/sec). The FTA measure of the threshold of architectural damage for conventional sensitive structures is 100 VdB, which correlates to a peak particle velocity of about 0.2 in/sec.

STATE

California Government Code Section 65302(f) encourages each local governmental entity to perform noise studies and implement a noise element as part of its General Plan. In addition, the California Office of Planning and Research has published guidelines for preparing noise elements, which include recommendations for evaluating the compatibility of various land uses as a function of community noise exposure. The State land use compatibility guidelines are listed in **Noise & Vibration Table 1**. Refer to **Noise Appendix A** for definitions of the terms used in this table and subsequent sections.

Noise & Vibration Table 1 - Land Use Compatibility for Community Noise Environment



Normally Acceptable	Specified land use is satisfactory, based upon the assumption that any buildings involved are of normal conventional construction, without any special noise insulation requirements.
Conditionally Acceptable	New construction or development should be undertaken only after a detailed analysis of the noise reduction requirements is made and needed noise insulation features are included in the design.
Normally Unacceptable	New construction or development should be discouraged. If new construction or development does proceed, a detailed analysis of the noise reduction requirement must be made and needed noise insulation features included in the design.
Clearly Unacceptable	New construction or development generally should not be undertaken.

Source: State of California General Plan Guidelines, Office of Planning and Research, June 1990.

The State of California, Office of Noise Control, prepared a Model Community Noise Control Ordinance, which provides guidance for acceptable noise levels in the absence of local noise standards. The Model also contains a definition of a simple tone, or "pure tone," in terms of one-third octave band sound pressure levels that can be used to determine whether a noise source contains annoying tonal components. The Model Community Noise Control Ordinance further recommends that, when a pure tone is present, the applicable noise standard should be lowered (made more stringent) by 5 dBA.

Other State LORS include the California Occupational Safety and Health Administration (Cal-OSHA) regulations.

California Environmental Quality Act

CEQA requires that significant environmental impacts be identified, and that such impacts be eliminated or mitigated to the extent feasible. Section XI of Appendix G of CEQA Guidelines (Cal. Code Regs., tit. 14, App. G) sets forth some characteristics that may signify a potentially significant impact. Specifically, a significant effect from noise may exist if a project would result in:

a) exposure of persons to, or generation of, noise levels in excess of standards established in the local General Plan or noise ordinance, or applicable standards of other agencies;

b) exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels;

c) a substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project; or

d) a substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project.

The Energy Commission staff, in applying Item c) above to the analysis of this and other projects, has concluded that a potential for a significant noise impact exists where the noise of the project plus the background exceeds the background by 5 dBA L_{90} or more at the nearest noise sensitive receptor.

Staff considers it reasonable to assume that an increase in background noise levels up to 5 dBA in a rural setting is insignificant; an increase of more than 10 dBA is clearly significant. An increase between 5 and 10 dBA should be considered adverse, but may be either significant or insignificant, depending on the particular circumstances of a case.

Factors to be considered in determining the significance of an adverse impact as defined above include:

1. the resulting noise level[1]

[1] For example, a noise level of 40 dBA would be considered quiet in many locations. A noise limit of 40 dBA would be consistent with the recommendations of the California Model Community Noise Control Ordinance for rural environments, and with the data supporting the noise guidelines of the World Health Organization. If the project would create an increase in ambient noise no greater than 10 dBA at nearby sensitive receptors, and the resulting noise level would be 40 dBA or less, the project noise level would likely be insignificant.

2. the duration and frequency of the noise;
3. the number of people affected; and
4. the land use designation of the affected receptor sites.

Staff usually considers noise due to construction activities to be insignificant if:

1. The construction activity is temporary,
2. Use of heavy equipment and noisy activities is limited to daytime hours, and
3. All feasible noise abatement measures are implemented for noise-producing equipment.

Cal-OSHA

Cal-OSHA has promulgated Occupational Noise Exposure Regulations (Cal. Code Regs., tit. 8, §§ 5095-5099) that set employee noise exposure limits. These standards are equivalent to the federal OSHA standards (see **Noise Appendix A, Table A4**).

LOCAL

Riverside County General Plan Noise Element

The Noise Element of the Riverside County General Plan contains standards, policies and procedures that are intended to minimize noise impacts to the community. The noise level standards for new projects, including non-transportation noise sources, employ the Community Noise Equivalent Level (CNEL) or Day-Night Level (Ldn), and are similar to those shown by **Noise and Vibration Table 1**. Specifically, the County Noise Element standards for residential land uses are: Normally Acceptable: CNEL or Ldn up to 60 dB; Conditionally Acceptable: up to 70 dB CNEL or Ldn.

Riverside County Code

Riverside County has adopted restrictions affecting construction noise sources in Chapter 15.04 of the Riverside County Code. Construction within one-quarter mile of an occupied residence is prohibited between the hours of 6 p.m. and 6 a.m., except as allowed with the written consent of the building official.

City of Blythe General Plan Noise Element

The City of Blythe is currently applying a draft Noise Element of the General Plan; the draft provided to Energy Commission staff in March 2002 (affirmed in September 2003) applies noise standards using a table similar to **Noise & Vibration Table 1**. The draft policy for new development of industrial or other noise-generating land uses prohibits development if resulting noise levels would exceed 60 dB Ldn or CNEL at the boundary of areas containing or planned and zoned for residential or other noise-sensitive land uses.

SETTING

PROJECT BACKGROUND

The BEP II project involves the construction and operation of a nominal 520-megawatt (MW) combined cycle power plant, which is proposed to be an addition to the approved Blythe Energy Project (BEP I) described by 99-AFC-8, in the City of Blythe. The project is comprised of two natural gas combustion turbines with electrical inlet chillers or evaporative inlet air coolers, two heat recovery steam generators, and a condensing steam turbine. Mechanical draft cooling towers would be employed. The BEP II would be connected to the Buck Blvd. substation, which in turn would connect to the proposed Imperial Irrigation District Southwest Transmission Project transmission system. The BEP II would connect to the BEP I natural gas supply line.

The equipment that has the greatest potential to generate significant noise levels includes the gas and steam turbines, steam generators, the auxiliary boiler, pumps, motors, main transformers, and the mechanical draft evaporative cooling towers.

Power Plant Site

This site is located within the City of Blythe. Land uses in the project vicinity include agricultural, industrial (BEP I), and residential uses.

The BEP II would be constructed on currently vacant land west of the BEP I power plant site. The nearest noise sensitive use is a home at 16531 Hobsonway, about 2,728 feet from the site boundary. This residence is located in Riverside County.

Linear Facilities

The BEP II would connect with the Western electrical transmission system via the existing Devers substation, which will require a 118-mile off-site transmission line. The transmission line would be part of the proposed Imperial Irrigation District Southwest Transmission Project.

EXISTING NOISE LEVELS

In order to predict the likely noise effects of the project on adjacent sensitive receptors, the applicant commissioned an ambient noise survey in the area (BEP II 2002a). The survey was conducted November 2-3, 1999 as part of the environmental study for the BEP I AFC (99-AFC-8). The noise survey was conducted using a Metrosonics dB308 data logger meeting the requirements of the American National Standards Institute (ANSI) for Type 1 sound level measurement systems. The applicant's noise survey monitored existing noise levels at the commercial/industrial building at 16275 Hobsonway, which is about 1,425 feet from the project boundary, and about 600 feet north of I-10. The nearest house is located farther from the project boundary, and closer to I-10, than the measurement site.

Noise & Vibration Table 2 summarizes the ambient noise measurement results (BEP II 2002d).

Noise & Vibration Table 2 - Measured Noise Levels at 16275 Hobsonway: November 2-3, 1999

Time of Day	Noise Level, dBA			
	Leq	L10	L50	L90
1400	51.3	55	50	44
1500	51.0	54	49	44
1600	52.3	56	51	46
1700	56.5	59	55	51
1800	56.5	59	56	52
1900	58.2	61	57	52
2000	58.5	62	58	53
2100	56.6	60	55	50
2200	55.2	58	54	50
2300	52.7	55	52	49
0000	57.4	62	56	50
0100	55.9	60	54	48
0200	55.4	59	54	49
0300	54.5	58	53	48
0400	54.7	59	52	45
0500	57.3	61	55	49
0600	56.0	59	54	49
0700	53.3	57	52	47
0800	52.9	57	51	45
0900	50.6	54	49	44
1000	50.6	54	49	44
1100	49.4	52	48	43
1200	48.0	51	47	42
1300	51.4	55	50	44
1400	51.0	54	50	45
25-hr. average	54.8	57	52	47

The calculated Ldn was 61.9 dB, and the calculated CNEL was 62.3 dB. In general, the environment in the immediate vicinity of the project site can be described as relatively quiet. The dominant background noise source was traffic on I-10, and the quietest period of the 24-hour day was during daytime hours (8 a.m. to 3 p.m.). The quietest period was also a period with low wind velocities. The average L90 during the quietest contiguous 4-hour period of the day was 43 dBA.

The hours experiencing the highest noise levels were during a relatively cool time of night, which could have resulted in improved transmission of traffic noise toward the measurement site.

The approved BEP I (99-AFC-8), once placed into operation, will add to the ambient noise levels. The predicted BEP I noise level is 44.9 dBA. When added to the L90 for the quietest contiguous 4-hour period of the day (43 dBA), the ambient noise level will be 47 dBA, an increase of 4 dBA over the ambient noise level (L90) that existed in 1999 without the BEP I.

The applicant has stated that ambient (traffic) noise levels at the nearest house (16531 Hobsonway) would be higher than those measured at 16275 Hobsonway because the house is closer to I-10, and is elevated above that freeway (BEP II 2002d).

IMPACTS

Noise impacts associated with the project can be created by short-term construction activities, and by normal long-term operation of the power plant.

PROJECT SPECIFIC IMPACTS — CONSTRUCTION

Community Effects

General Construction Noise

Construction noise is usually considered a temporary phenomenon. Sensitive receptors near the plant site could be affected by noise from these activities. Construction of an industrial facility such as a power plant is typically noisier than permissible under usual noise ordinances. In order to allow the construction of new facilities, construction noise during certain hours is commonly exempt from enforcement by local ordinances. Riverside County regulates the permissible hours of construction, but does not have any specific noise limits during those hours.

The applicant has prepared an analysis of construction noise impacts, listing predicted noise levels due to specific types of equipment and of generalized construction activities (BEP II 2002d). No pile driving would be required (BEP II 2002g). The construction noise analysis for the worst-case noise sources indicated that the maximum noise level predicted at the nearest residence would be about 56 dBA, including ambient noise. The applicant opined that, since this level of noise is close to the maximum average noise level at the nearest residence, the construction noise would likely be audible during traffic lull periods.

There are no other noise-sensitive receptors within the range of distances where construction noise would be expected to be audible.

The changes in ambient noise levels would be of a temporary nature. The unmitigated increases in ambient noise levels due to construction are expected to be insignificant.

Based upon the potential noise impacts of construction, the Energy Commission staff recommends the inclusion of three Conditions of Certification (**NOISE-1**, **NOISE-2**, and **NOISE-8**) to monitor and mitigate potential construction noise impacts.

Because construction activity would be limited by the proposed Condition of Certification **NOISE-8**, and would be of limited duration, potential construction noise impacts to receptors in the BEP II project area are considered to be less than significant.

Steam Blows

Typically, the steam blows during construction and start-up create the loudest noise encountered during the construction phase. Steam blows are necessary after erection and assembly of the feedwater and steam systems because the piping and tubing that comprises the steam path accumulate dirt, rust, scale, and construction debris such as weld spatter, dropped welding rods, and the like. If the plant were to start up without thoroughly cleaning out the piping and tubing, all this debris would find its way into the steam turbine, quickly destroying the machine.

In order to prevent this, before the steam system is connected to the turbine, the steam line is temporarily routed to the atmosphere. High-pressure steam is then raised in the heat recovery steam generator (HRSG) or a temporary boiler and allowed to escape to the atmosphere through the steam piping. This flushing action, referred to as a steam blow, is effective at cleaning out the steam system. A series of short steam blows, lasting two or three minutes each, is performed several times daily over a period of two or three weeks. At the end of this procedure, the steam line is connected to the steam turbine, which is then ready for operation.

In recent years, a new, quieter steam blow process, variously referred to as QuietBlow™ or Silentsteam™, has become popular. This method utilizes lower pressure steam over a continuous period of 36 hours or so. Resulting noise levels reach only about 80 dBA at 100 feet; noise levels at nearby receptors are typically similar to the daytime ambient background noise level, and thus barely noticeable. Even more recently, compressed air has been substituted for steam in the continuous blow process; resulting noise levels are similar.

According to the applicant, a low-pressure high velocity cleaning method would be employed that would produce noise levels ranging from 75 to 80 dBA at 100 feet from the outlet, or about 39 to 44 dBA at the nearest residence, after accounting for atmospheric absorption (BEP II 2002g). The resulting noise levels would be below ambient noise levels. The predicted steam blow noise levels would not interfere with speech outdoors.

Energy Commission staff proposes that the plant owner be required to utilize a low-pressure steam cleaning method (see proposed Condition of Certification **NOISE-4** below).

Energy Commission staff further proposes a notification process to make neighbors aware of scheduled steam blows (see proposed Condition of Certification **NOISE-5** below).

Linear Facilities

A new natural gas line would be installed from the project site to the existing line serving the BEP I.

Trenching for the proposed pipeline would involve use of diesel-powered equipment. Noise produced by this equipment could be annoying to nearby residents. To ensure that trench construction noise would not be significant, staff has recommended Condition of Certification **NOISE-8**.

Worker Effects

The applicant has acknowledged the need to protect construction workers from noise hazards, and has recognized those applicable LORS that would protect construction workers (BEP II 2002a). To ensure that construction workers are, in fact, adequately protected, Energy Commission staff proposes Condition of Certification **NOISE-3**.

PROJECT SPECIFIC IMPACTS — OPERATION

Community Effects

The applicant has incorporated noise reduction measures into the design of the project. The applicant intends to achieve noise level standards that would prevent a significant noise impact as defined by staff; the allowable noise levels under LORS could be substantially higher than existing background noise levels.

Power Plant Operation

During its operating life, the BEP II represents essentially a steady, continuous noise source day and night. Occasional brief increases in noise levels would occur as steam relief valves open to vent pressure, or during startup or shutdown as the plant transitions to and from steady-state operation. At other times, such as when the plant is shut down for lack of dispatch or for maintenance, noise levels would decrease.

The primary noise sources anticipated from the 520 MW facility include the combustion turbines, steam turbine generators, relief valves, circulating water pumps, HRSG exhaust stacks, and cooling towers. The noise emitted by power plants during normal operations is generally broadband, steady state in nature (BEP II 2002g), as demonstrated by the applicant's noise level data. The resulting hourly average noise levels are typically dominated by the steady-state noise sources.

The applicant conducted noise measurements at a similar power plant, and performed acoustical calculations to determine the facility noise emissions, and to develop noise mitigation measures. The calculations were based on measured noise data for the major equipment planned for the facility (BEP II 2002g). The modeling assumed that the noise levels and frequency content of the Siemens-Westinghouse power plant at Choteau, Oklahoma would be representative of the noise produced by the BEP II. The predicted noise level was 66 dBA at a distance of 400 feet.

Specific noise mitigation measures evaluated by the applicant (BEP II 2002g) included:

∉ Standard cooling tower without additional noise reduction features

∉ Standard power plant noise control features for HRSG units, including thermally insulated casings and inlet ductwork, but without exhaust stack silencing baffles or acoustical insulation.

Noise & Vibration Table 3 lists the predicted project noise levels at the nearest sensitive receptor in terms of the background noise level (L_{90}). The predicted noise levels include the applicant's assumptions listed above. It is assumed that the noise levels experienced at more distant receivers would be lower than those shown by **Noise & Vibration Table 3.**

The applicant has also described the potential noise effects of replacing the electrical inlet chillers with mechanical refrigeration chillers, assuming that the near-field sound pressure levels would be limited to 85 dBA (BEP II 2002f). The applicant concluded that the proposed inlet chilling equipment would not produce noise that is significantly different from the noise produced during steady-state plant operation.

**Noise & Vibration Table 3 –
Summary of Predicted Operational Noise Levels**

Sensitive Receptor Site	Background Noise Level (L90), dBA						
	Ambient (1999)	BEP	Ambient plus BEP	BEP II	Cumulative	Change re: Ambient (1999)	Change re: Ambient plus BEP
16531 Hobsonway	43	44.9	47.1	49.2	51.1	+8.1	+4
Source: BEP II 2002d * Average of L90 values for the four quietest contiguous hours at 16275 Hobsonway.							

The predicted BEP II power plant noise level would exceed the ambient noise level measured in 1999 by about 8 dB. It would also exceed the estimated current ambient noise level (1999 plus BEP) by 4 dB. Given that the approval of the BEP I allowed a 4 dBA increase in ambient noise levels as compared to the pre-BEP I (1999) ambient noise level conditions, Energy Commission staff cannot support any additional potentially significant increases in ambient noise levels as a result of the BEP II, and therefore recommends that the increase in noise levels due to BEP II be limited to the maximum practical extent, so that the change at the nearest sensitive receptor would be barely perceptible.

The proposed Condition of Certification **NOISE-6** would require that the noise level produced by the BEP II plant operation not exceed 47 dBA L_{eq} at the nearest residence. This would allow the BEP II power plant to generate the same amount of noise at the nearest residence as allowed for the BEP I, but would also ensure that the cumulative nighttime background noise level (L_{90}) at the nearest residence would not increase by more than 3 dBA over that with BEP I operating. This increase would be barely perceptible, and would not be expected to be annoying. Noise due to the plant operations would not exceed the standards of the LORS at any sensitive receptor.

Specifically, implementation of the proposed Condition of Certification **NOISE-6** would result in the noise levels shown in **Noise & Vibration Table 4**.

Noise & Vibration Table 4
- Conditioned Plant Operational Noise Levels and Resulting Ambient Noise Levels

Site	Noise Level, dBA				
	4-Hour Background Noise Level with BEP	Permitted BEP II Plant Noise Level	Cumulative Noise Level	Resulting Increase in Ambient Noise Levels re:	
				Ambient (1999)	Ambient plus BEP
16531 Hobsonway	47	47	50	+7	+3

The proposed Condition of Certification **NOISE-6** would require that the owner reduce BEP II noise levels by about 2 dBA. Energy Commission staff prefers that power plant noise level reductions be achieved by applying on-site noise abatement measures. To date, the applicant has provided no technical or feasibility data to support a determination that the lower noise levels required by the recommended Conditions of Certification cannot be attained.

Staff believes, on the basis of Energy Commission experience with other power plants, that significant additional noise reduction can be achieved using a variety of measures, such as those listed below:

- low-noise equipment such as pumps and electrical transformers
- quieter gas turbine inlet air mufflers
- noise attenuating vents on turbine generator enclosures
- noise lagging on the HRSG transition ducts
- low noise cooling fans for the cooling tower that incorporate additional fan blades or specially-designed “super low noise” fans combined with noise-reducing motor enclosures
- noise barriers adjacent to either sources or receivers

The applicant has neither stated whether such measures have been considered in the plant acoustical design, nor whether they consider them to be feasible. Staff notes that the above design features have been found technologically feasible for other power plant installations.

Tonal and Intermittent Noises

One possible source of annoyance would be strong tonal noises. Tonal noises are individual sounds (such as pure tones) that, while not louder than permissible levels, stand out in sound quality. The applicant has stated that no strong tonal noises would be generated during the operation of the project.

Noise levels generated during system start-up and shutdown may be elevated compared to steady-state operations, as steam relief valves may be employed for short periods under those conditions. The applicant has indicated that the duration of start-up periods could be approximately three hours (BEP II 2002g). The potentially significant noise sources during start-up would be the start-up steam system and the high-pressure steam bypass station. Based on the system design specifications, the predicted start-up steam vent noise levels would be in the range of 50 to 55 dBA at the nearest residence. The applicant's data does not describe the durations of these steam releases, but such releases are typically relatively short, in the range of a few minutes per occurrence. The predicted steam bypass station noise level would be about 39 to 44 dBA at the nearest residence; the event duration could be in the range of 30 minutes to one hour or more.

To ensure that no strong tonal noises are present and that intermittent noises are mitigated, Energy Commission staff proposes Condition of Certification **NOISE-6**, below, which requires the applicant to ensure that there are no pure tones, and to mitigate the noise from steam relief valves.

Linear Facilities

The electrical output of the plant would be connected to the Buck Blvd. substation, which in turn would be connected to the proposed Imperial Irrigation District Southwest Transmission Project transmission lines. The Buck Blvd. substation is located at the northeastern corner of the BEP I site. Connections between the power plant and the substation would be contained within the BEP I and BEP II property boundaries. Since there are no sensitive receivers in proximity to these connections, no noise impacts are expected.

Worker Effects

The applicant recognizes the need to protect plant operating and maintenance personnel from noise hazards, and has committed to comply with applicable LORS (BEP II 2002a). Signs would be posted in areas of the plant with noise levels exceeding 85 dBA (the level that OSHA recognizes as a threat to workers' hearing), and hearing protection would be required. The applicant would implement a comprehensive hearing conservation program. To ensure that construction workers are, in fact, adequately protected, Energy Commission staff proposes Conditions of Certification **NOISE-3** and **NOISE-7**, below.

CUMULATIVE IMPACTS

Section 15130 of the *CEQA Guidelines* (Cal. Code Regs., tit. 14) requires a discussion of cumulative environmental impacts. Cumulative impacts are two or more individual impacts that, when considered together, are considerable or that compound or increase other environmental impacts. The *CEQA Guidelines* require that the discussion reflect the severity of the impacts and the likelihood of their occurrence, but need not provide as much detail as the discussion of the impacts attributable to the project alone.

Pursuant to CEQA, a cumulative impacts analysis can be performed by either 1) summarizing growth projections in an adopted general plan or in a prior certified environmental document, or 2) compiling a list of past, present, and probable future projects producing related or cumulative impacts. The second method has been utilized for the purposes of this Staff Assessment.

The AFC identified that the BEP II could contribute to cumulative noise impacts in the project study area (BEP II 2002d), and staff agrees this is the case. Without mitigation, BEP II could contribute to a potential significant cumulative noise impact due to the cumulative noise level of two power plants (BEP I and BEP II) in proximity to a sensitive receiver. To ensure that the cumulative effect of the two noise sources would be insignificant, Energy Commission staff has proposed Condition of Certification **NOISE-6**.

The electrical output of the plant would be connected to the Buck Blvd. substation, which in turn would be connected to the proposed Imperial Irrigation District Southwest Transmission Project transmission lines. This would be a 118-mile off-site transmission line, and its environmental noise effects are addressed by an EIR/EIS prepared by the District (BEP II 2002h). According to the EIR/EIS, the transmission line project could result in noise impacts due to construction, blasting, and noise due to corona discharge hum and onsite maintenance.

Construction noise impacts would be mitigated in the EIR/EIS by limits on the time of day for construction, and by requirements for adequate mufflers. Blasting impacts would be mitigated in the EIR/EIS by establishing limits on the time of day of blasting, by requiring notice to sensitive receptors when blasting is planned, and by requiring a blasting plan approved by the BLM.

Since corona discharge hum is predicted to be 44 dBA directly under the transmission lines during inclement weather, and 20 dBA in dry weather, it was not considered significant. Other operational noise such as vehicle traffic was also considered insignificant. No additional mitigation would be required.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and the low-income population is less than fifty percent within the same radius.

Based on the noise analysis, staff has identified a potentially significant direct impact resulting from the operation of the project, but with the mitigation proposed in the Conditions of Certification, the impact would be reduced to less than significant. Therefore, there is no potential disparate impact on the minority population, and there are no noise environmental justice issues related to this project.

FACILITY CLOSURE

In the future, upon closure of the BEP II, all operational noise from the entire BEP II site would cease, and no further adverse noise impacts from operation of the BEP II would be possible. The remaining potential temporary noise source is the dismantling of the structures and equipment, and any site restoration work that may be performed. Since this noise would be similar to that caused by the original construction of the BEP II, it can be treated similarly. That is, noisy work can be performed during daytime hours, with machinery and equipment properly equipped with mufflers. Any noise LORS that are in existence at that time would apply; applicable Conditions of Certification included in the Energy Commission Decision would also apply unless modified.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff concludes that BEP II, with the recommended mitigation, could be built and operated to comply with all applicable noise laws, ordinances, regulations, and standards. Energy Commission staff further concludes that if the BEP II facility were designed as described above, and further mitigated as described below in the proposed Conditions of Certification, it would not be expected to produce significant adverse noise impacts. The following proposed Conditions of Certification will ensure compliance with all applicable noise LORS, and ensure that the project would not result in a significant increase in ambient noise levels.

PROPOSED CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of ground disturbance, the project owner shall notify by mail all residents within one-half mile of the site and the linear facilities of the commencement of project construction. At the same time, the project owner shall establish a telephone number for use by the public to report any undesirable noise conditions associated with the construction and operation of the project. If the telephone is not staffed 24 hours per day, the project owner shall include an automatic answering feature, with date and time stamp recording, to answer calls when the phone is unattended. This telephone number shall be posted at the project site during construction in a manner visible to passersby. This telephone number shall be maintained until the project has been operational for at least one year.

Verification: Prior to ground disturbance, the project owner shall transmit to the CPM a statement, signed by the project manager, stating that the above notification has been performed, and describing the method of that notification, verifying that the telephone number has been established and posted at the site, and giving that telephone number.

NOISE-2 Throughout the construction and operation of the project, the project owner shall document, investigate, evaluate, and attempt to resolve all project-related noise complaints. The project owner or authorized agent shall:

- Use the Noise Complaint Resolution Form (below), or functionally equivalent procedure acceptable to the CPM, to document and respond to each noise complaint;
- Attempt to contact the person(s) making the noise complaint within 24 hours;
- Conduct an investigation to determine the source of noise related to the complaint;
- If the noise is project related, take all feasible measures to reduce the noise at its source; and
- Submit a report documenting the complaint and the actions taken. The report shall include: a complaint summary, including final results of noise reduction efforts; and if obtainable, a signed statement by the complainant stating that the noise problem is resolved to the complainant's satisfaction.

Verification: Within 5 business days of receiving a noise complaint, the project owner shall file with the City of Blythe Development Services Department, the Riverside County Planning Department, and the CPM a copy of the Noise Complaint Resolution Form, documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a 3-business day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is implemented.

NOISE-3 The project owner shall submit to the CPM for review and approval an employee construction noise exposure control program. The noise control program shall be used to reduce employee exposure to high noise levels during construction and also to comply with applicable OSHA and Cal-OSHA standards.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM the noise control program. The project owner shall make the program available to Cal-OSHA upon request.

NOISE-4 The project owner shall implement a low-pressure steam blow procedure in accordance with the requirements of the CPM.

Verification: At least 15 days prior to any low-pressure continuous steam blow, the project owner shall submit to the CPM information describing the process, including the noise levels expected and the projected time schedule for execution of the process.

NOISE-5 Prior to the first steam blow(s), the project owner shall notify all residents or business owners within one mile of the site of the planned steam blow activity, and shall make the notification available to other area residents in an appropriate manner.

The notification may be in the form of letters to the area residences, telephone calls, fliers or other effective means. The notification shall include a description of the purpose and nature of the steam blow(s), the proposed schedule, the expected sound levels, and the explanation that it is a one-time operation and not a part of normal plant operations.

Verification: The project owner shall notify residents and businesses at least 15 days prior to the first steam blow(s). Within five (5) days of notifying these entities, the project owner shall send a letter to the CPM confirming that they have been notified of the planned steam blow activities, including a description of the method(s) of that notification.

NOISE-6 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise level produced by operation of the project will not exceed an hourly average noise level (L_{eq}) of more than 47 dBA, measured at any residence.

No new pure tone components may be introduced. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints. Steam relief valves shall be adequately muffled to preclude noise that draws legitimate complaints.

A. Within 30 days of the project first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey at or near the residence at 16531 Hobsonway. The noise survey shall also include short-term measurement of one-third octave band sound pressure levels to ensure that no new pure-tone noise components have been introduced.

B. If the results from the noise survey indicate that the noise level due to the plant operations exceeds the noise standard listed above for any given hour during the 25-hour period, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits.

C. If the results from the noise survey indicates that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

Verification: Within 30 days after completing the community noise survey, the project owner shall submit a summary report of the survey to the City of Blythe Development Services Department, to the Riverside County Planning Department, and to the CPM. Included in the post-construction survey report will be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. Within 30 days of completion of installation of these measures, the project owner shall submit to the CPM a summary report of a new noise survey, performed as described above and showing compliance with this condition.

NOISE-7 Following the project first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct an occupational noise survey to identify the noise hazardous areas in the facility.

The survey shall be conducted by a qualified person in accordance with the provisions of Title 8, California Code of Regulations, sections 5095-5099 (Article 105) and Title 29, Code of Federal Regulations, section 1910.95. The survey results shall be used to determine the magnitude of employee noise exposure.

The project owner shall prepare a report of the survey results and, if necessary, identify proposed measures that will be employed to comply with the applicable California and federal regulations.

Verification: Within 30 days after completing the survey, the project owner shall submit the noise survey report to the CPM. The project owner shall make the report available to OSHA and Cal-OSHA upon request.

NOISE-8 Noisy construction or demolition work (typically that involving the use of powered equipment or impact tools) shall be restricted to the hours of 6:00 a.m. to 6:00 p.m.

Haul trucks and other engine-powered equipment shall be equipped with adequate mufflers. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies.

Verification: The project owner shall transmit to the CPM in the first Monthly Construction Report a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

EXHIBIT 1 - NOISE COMPLAINT RESOLUTION FORM

Blythe Energy Project II (02-AFC-1)
NOISE COMPLAINT LOG NUMBER ________________________ Complainant's name and address: Phone number: ________________________
Date complaint received: ________________________ Time complaint received: ________________________
Nature of noise complaint:
Definition of problem after investigation by plant personnel: Date complainant first contacted: ________________________
Initial noise levels at 3 feet from noise source _________ dBA Date: _____________ Initial noise levels at complainant's property: __________ dBA Date: ____________ Final noise levels at 3 feet from noise source: ________ dBA Date: _____________ Final noise levels at complainant's property: __________ dBA Date: ____________
Description of corrective measures taken: Complainant's signature: ________________________ Date: ____________
Approximate installed cost of corrective measures: $ ____________ Date installation completed: ____________ Date first letter sent to complainant: ____________ (copy attached) Date final letter sent to complainant: ____________(copy attached)
This information is certified to be correct: Plant Manager's Signature: ________________________

(Attach additional pages and supporting documentation, as required).

REFERENCES

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NOISE APPENDIX A
FUNDAMENTAL CONCEPTS OF COMMUNITY NOISE

To describe noise environments and to assess impacts on noise sensitive area, a frequency weighting measure, which simulates human perception, is customarily used. It has been found that A-weighting of sound intensities best reflects the human ear's reduced sensitivity to low frequencies and correlates well with human perceptions of the annoying aspects of noise. The A-weighted decibel scale (dBA) is cited in most noise criteria. Decibels are logarithmic units that conveniently compare the wide range of sound intensities to which the human ear is sensitive. **Noise Table A1** provides a description of technical terms related to noise.

Noise environments and consequences of human activities are usually well represented by an equivalent A-weighted sound level over a given time period (Leq), or by average day and night A-weighted sound levels with a nighttime weighting of 10 dBA (Ldn). Noise levels are generally considered low when ambient levels are below 45 dBA, moderate in the 45 to 60 dBA range, and high above 60 dBA. Outdoor day-night sound levels vary over 50 dBA depending on the specific type of land use. Typical Ldn values might be 35 dBA for a wilderness area, 50 dBA for a small town or wooded residential area, 65 to 75 dBA for a major metropolis downtown (e.g., San Francisco), and 80 to 85 dBA near a freeway or airport. Although people often accept the higher levels associated with very noisy urban residential and residential-commercial zones, they nevertheless are considered to be levels of noise adverse to public health.

Various environments can be characterized by noise levels that are generally considered acceptable or unacceptable. Lower levels are expected in rural or suburban areas than what would be expected for commercial or industrial zones. Nighttime ambient levels in urban environments are about seven decibels lower than the corresponding average daytime levels. The day-to-night difference in rural areas away from roads and other human activity can be considerably less. Areas with full-time human occupation that are subject to nighttime noise, which does not decrease relative to daytime levels, are often considered objectionable. Noise levels above 45 dBA at night can result in the onset of sleep interference effects (Effects of Noise on People, U.S. Environmental Protection Agency, December 31,1971). At 70 dBA, sleep interference effects become considerable.

In order to help the reader understand the concept of noise in decibels (dBA), **Noise Table A2** has been provided to illustrate common noises and their associated sound levels, in dBA.

Noise Table A1 Definition of Some Technical Terms Related to Noise	
Terms	**Definitions**
Decibel, dB	A unit describing the amplitude of sound, equal to 20 times the logarithm to the base 10 of the ratio of the pressure of the sound measured to the reference pressure, which is 20 micropascals (20 micronewtons per square meter).
Frequency, Hz	The number of complete pressure fluctuations per second above and below atmospheric pressure.
A-Weighted Sound Level, dBA	The sound pressure level in decibels as measured on a Sound Level Meter using the A-weighting filter network. The A-weighting filter de-emphasizes the very low and very high frequency components of the sound in a manner similar to the frequency response of the human ear and correlates well with subjective reactions to noise. All sound levels in this testimony are A-weighted.
L_{10}, L_{50}, & L_{90}	The A-weighted noise levels that are exceeded 10%, 50%, and 90% of the time, respectively, during the measurement period. L_{90} is generally taken as the background noise level.
Equivalent Noise Level, L_{eq}	The energy average A-weighted noise level during the Noise Level measurement period.
Community Noise Equivalent Level, CNEL	The average A-weighted noise level during a 24-hour day, obtained after addition of 4.8 decibels to levels in the evening from 7 p.m. to 10 p.m., and after addition of 10 decibels to sound levels in the night between 10 p.m. and 7 a.m.
Day-Night Level, L_{dn} or DNL	The Average A-weighted noise level during a 24-hour day, obtained after addition of 10 decibels to levels measured in the night between 10 p.m. and 7 a.m.
Ambient Noise Level	The composite of noise from all sources, near and far. The normal or existing level of environmental noise at a given location.
Intrusive Noise	That noise that intrudes over and above the existing ambient noise at a given location. The relative intrusiveness of a sound depends upon its amplitude, duration, frequency, and time of occurrence and tonal or informational content as well as the prevailing ambient noise level.
Pure Tone	A pure tone is defined by the Model Community Noise Control Ordinance as existing if the one-third octave band sound pressure level in the band with the tone exceeds the arithmetic average of the two contiguous bands by 5 decibels (dB) for center frequencies of 500 Hz and above, or by 8 dB for center frequencies between 160 Hz and 400 Hz, or by 15 dB for center frequencies less than or equal to 125 Hz.

Source: Guidelines for the Preparation and Content of Noise Elements of the General Plan, Model Community Noise Control Ordinance, California Department of Health Services 1976, 1977.

Noise Table A2 Typical Environmental and Industry Sound Levels			
Noise Source (at distance)	A-Weighted Sound Level in Decibels (dBA)	Noise Environment	Subjective Impression
Civil Defense Siren (100')	140-130		Pain Threshold
Jet Takeoff (200')	120		Very Loud
Very Loud Music	110	Rock Music Concert	
Pile Driver (50')	100		
Ambulance Siren (100')	90	Boiler Room	
Freight Cars (50')	85		
Pneumatic Drill (50')	80	Printing Press Kitchen with Garbage Disposal Running	Loud
Freeway (100')	70		Moderately Loud
Vacuum Cleaner (100')	60	Data Processing Center Department Store/Office	
Light Traffic (100')	50	Private Business Office	
Large Transformer (200')	40		Quiet
Soft Whisper (5')	30	Quiet Bedroom	
	20	Recording Studio	
	10		Threshold of Hearing

Source: Handbook of Noise Measurement, Arnold P.G. Peterson, 1980

SUBJECTIVE RESPONSE TO NOISE

The adverse effects of noise on people can be classified into three general categories:

∉ Subjective effects of annoyance, nuisance, dissatisfaction.

∉ Interference with activities such as speech, sleep, and learning.

∉ Physiological effects such as anxiety or hearing loss.

The sound levels associated with environmental noise, in almost every case, produce effects only in the first two categories. Workers in industrial plants can experience noise effects in the last category. There is no completely satisfactory way to measure the subjective effects of noise, or of the corresponding reactions of annoyance and dissatisfaction, primarily because of the wide variation in individual tolerance of noise.

One way to determine a person's subjective reaction to a new noise is to compare the level of the existing (background) noise, to which one has become accustomed, with the level of the new noise. In general, the more the level or the tonal variations of a new

noise exceed the previously existing ambient noise level or tonal quality, the less acceptable the new noise will be, as judged by the exposed individual.
With regard to increases in A-weighted noise levels, knowledge of the following relationships (Kryter 1970) can be helpful in understanding the significance of human exposure to noise.

1. Except under special conditions, a change in sound level of one dB cannot be perceived.
2. Outside of the laboratory, a three dB change is considered a barely noticeable difference.
3. A change in level of at least five dB is required before any noticeable change in community response would be expected.
4. A ten dB change is subjectively heard as an approximate doubling in loudness and almost always causes an adverse community response.

COMBINATION OF SOUND LEVELS

People perceive both the level and frequency of sound in a non-linear way. A doubling of sound energy (for instance, from two identical automobiles passing simultaneously) creates a three dB increase (i.e., the resultant sound level is the sound level from a single passing automobile plus three dB). The rules for decibel addition used in community noise prediction are:

Noise Table A3
Addition of Decibel Values

When two decibel values differ by:	Add the following amount to the larger value
0 to 1 dB	3 dB
2 to 3 dB	2 dB
4 to 9 dB	1 dB
10 dB or more	0
Figures in this table are accurate to ± 1 dB.	

Source: Architectural Acoustics, M. David Egan, 1988

SOUND AND DISTANCE

Doubling the distance from a noise source reduces the sound pressure level by six dB.

Increasing the distance from a noise source ten times reduces the sound pressure level by 20 dB.

WORKER PROTECTION

OSHA noise regulations are designed to protect workers against the effects of noise exposure, and list permissible noise level exposure as a function of the amount of time to which the worker is exposed:

Noise Table A4
OSHA Worker Noise Exposure Standards

Duration of Noise (Hrs/day)	A-Weighted Noise Level (dBA)
8.0	90
6.0	92
4.0	95
3.0	97
2.0	100
1.5	102
1.0	105
0.5	110
0.25	115

Source: 29 C.F.R. § 1910.95

PUBLIC HEALTH

Ramesh Sundareswaran

INTRODUCTION

The purpose of staff's public health analysis is to determine if toxic air contaminants released from the proposed Blythe Energy Project II (BEP II) will have the potential to cause significant adverse public health impacts or to violate standards for public health protection. If potentially significant health impacts are identified, staff will evaluate mitigation measures to reduce such impacts to insignificant levels.

Staff addresses potential impacts of regulated or criteria air pollutants in the **Air Quality** section (please see **Public Health** Attachment A for a discussion of the health effects of criteria pollutants). Impacts on public and worker health from accidental releases of hazardous materials are examined in the **Hazardous Materials Management** section. Health effects from electromagnetic fields are discussed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project in wastewater streams are discussed in the **Soils and Water Resources** section. Plant releases in the form of hazardous and nonhazardous wastes are described in the **Waste Management** section.

METHOD OF ANALYSIS

Public health staff is concerned about toxic air contaminants to which the public could be exposed during project construction and routine operation. Following the release of toxic air contaminants into the air or water, people could come into contact with them through inhalation, dermal contact, or ingestion via contaminated food or water.

Air pollutants for which no air quality standards have been set are called noncriteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide, noncriteria pollutants have no state or national ambient (outdoor) air quality standards that specify levels considered safe for everyone.

Since noncriteria pollutants do not have such standards, a process known as health risk assessment is used to determine if people might be exposed to those types of pollutants at unhealthy levels. The risk assessment procedure consists of the following steps:

1. Identify the types and amounts of hazardous substances that BEP II could emit to the environment;
2. Estimate worst-case concentrations of project emissions in the environment using dispersion modeling;
3. Estimate amounts of pollutants to which people could be exposed through inhalation, ingestion, and dermal contact; and
4. Characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

Initially, a screening level risk assessment is performed using generic assumptions that are intentionally biased toward protection of public health. That is, a study is done that is designed to overestimate or maximize public potential health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the power plant will be much lower than the risks which are estimated by the assessment. This is accomplished by examining conditions that would lead to the highest, or worst-case, risks and then using those in the study. Such conditions include:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the highest ambient concentration of pollutants;
- using the type of air quality computer model which predicts the highest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are calculated to be the highest;
- using health-based standards designed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses); and
- assuming that an individual's exposure to cancer-causing agents occurs for 70 years.

A screening level risk assessment will, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities may also emit certain substances which could present a health hazard from noninhalation pathways of exposure (see CAPCOA, Table III-5). When these substances are present in facility emissions, the screening level analysis includes the following additional exposure pathways: soil ingestion, dermal exposure, and mother's milk (CAPCOA , p. III-19).

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) noncancer effects, and cancer risk (also long-term).

Acute health effects result from short-term (1-hour) exposure to relatively high concentrations of pollutants. Acute effects are temporary in nature, and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those which arise as a result of long term exposure to lower concentrations of pollutants. The exposure period is considered to be approximately from ten to one hundred percent of a lifetime (from seven to seventy years). Chronic health effects include diseases such as emphysema and heart disease.

The analysis for noncancer health effects compares the maximum project contaminant levels to safe levels called "reference exposure levels" or RELs (see CAPCOA, p. III-36). RELs are amounts of toxic substances to which people can be exposed and suffer no adverse health effects. These exposure levels are designed to protect the most sensitive individuals in the population, such as infants, the aged, and people suffering from illness or disease which makes them more sensitive to the effects of toxic substance exposure. RELs are based on the most sensitive adverse health effect reported in the medical and toxicological literature, and include margins of safety. The margin of safety addresses uncertainties associated with inconclusive scientific and technical information available at the time of standard setting and is meant to provide a reasonable degree of protection against hazards that research has not yet identified. The margin of safety is designed to prevent pollution levels that have been demonstrated to be harmful, as well as to prevent lower pollutant levels that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. Health protection is achieved if the estimated worst-case exposure is below the relevant reference exposure level. In such a case, an adequate margin of safety exists between the predicted exposure and the estimated threshold dose for toxicity.

If someone is exposed to multiple toxic substances, an adverse health effect could result, even if each individual substance is not present at harmful levels. Therefore, the assumption is made that the effects of each substance are additive. In those cases where the actions may be synergistic (where the effects are greater than the sum), this approach may underestimate the health impact (CAPCOA, p. III-37). In other cases, the effects may be antagonistic (where the effects are less than the sum), and the resultant health impact may be overstated.

For carcinogenic substances, the health assessment considers the risk (expressed in chances per million) of developing cancer and assumes that continuous exposure to the cancer-causing substance occurs over a 70-year lifetime. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound number based on worst-case assumptions. In reality, the risk is generally too small to actually be measured. For example, the ten in one million risk level represents a ten in one million increase in the normal risk of developing cancer over a lifetime, at the geographic location estimated to have the worst-case risk.

Cancer risk is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (called potency factors, these are published in the CAPCOA Guidelines), and the length of the exposure period. Cancer risks for each carcinogen are added to yield total cancer risk. The conservative nature of the screening assumptions used means that actual cancer risks are likely to be lower or even considerably lower than those estimated.

Failure to pass the initial screening analysis does not automatically indicate that the project would pose a significant risk to public health, but that a more detailed assessment, using more realistic project-specific assumptions, is necessary to more accurately determine potential public health risks.

SIGNIFICANCE CRITERIA

Commission staff determines the health effects of exposure to toxic emissions based on impacts to the maximum exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using worst-case assumptions, as described above.

As described earlier, non-criteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as cancer (long-term) health effects. Significance of project health impacts is determined separately for each of the three categories.

Acute and Chronic Noncancer Health Effects

Staff assesses the significance of non-cancer health effects by calculating a “hazard index”. A hazard index is a ratio comparing exposure from facility emissions to the reference (safe) exposure level. A ratio of less than one signifies that the worst-case exposure is below the safe level. The hazard index for every toxic substance which has the same type of health effect is added to yield a total hazard index. The total hazard index is calculated separately for acute and chronic effects. A total hazard index of less than one indicates that cumulative worst-case exposures are less than the reference exposure levels (safe levels). Under these conditions, health protection is likely to be achieved, even for sensitive members of the population. In such a case, staff presumes that there would be no significant non-cancer project-related public health impacts.

Cancer Risk

Staff relied upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986 (Health & Safety Code, §§ 25249.5 et seq.) for guidance to determine a cancer risk significance level. Title 22, California Code of Regulations, section 12703(b) states that “the risk level which represents no significant risk shall be one which is calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure.” This level of risk is equivalent to a cancer risk of ten in one million, or $10x10^{-6}$. An important distinction is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all cancer-causing chemicals. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than that which applies to Proposition 65.

The significant risk level of ten in one million is consistent with the level of significance adopted by the Mojave Desert Air Quality Management District pursuant to Health and Safety Code section 44362(b), which requires notification of nearby residents when an air district determines that there is a significant health risk from a facility.

As noted earlier, the initial risk analysis for a project is typically performed at a screening level that is designed to overstate actual risks, so that health protection can be ensured. When a screening analysis shows cancer risks to be above the significance level, refined assumptions would likely result in a lower, more realistic risk estimate. If project risk, based on refined assumptions, exceeds the significance level of ten in one million, staff would require appropriate measures to reduce risk to insignificance. If, after all risk reduction measures had been considered, a refined analysis identifies a cancer risk greater than ten in one million, staff would deem such risk to be significant, and would not recommend project approval.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following federal, state, and local LORS generally apply to the protection of public health. These provisions have established the basis for Energy Commission staff's determination regarding the significance and acceptability of project-related impacts on public health.

FEDERAL

Clean Air Act section 112 (42 United States Code section 7412*)*

Section 112 requires new sources which emit more than ten tons per year of any specified hazardous air pollutant (HAP) or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology.

STATE

California Health and Safety Code sections 39650 et seq.

These sections mandate the Air Resources Board and the Department of Health Services to establish safe exposure limits for toxic air pollutants and identify pertinent best available control technologies. They also require that the new source review rule for each air pollution control district include regulations that require new or modified procedures for controlling the emission of toxic air contaminants.

California Health and Safety Code section 41700

This section states that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

SETTING

This section describes the environment in the vicinity of the proposed project site from the public health perspective. Features of the natural environment, such as meteorology and terrain, affect the project's potential for causing impacts on public health. An emissions plume from a facility may affect elevated areas before lower terrain areas, due to a reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain can often be subjected to increased pollutant impacts. Also, the types of land use near a site influence the surrounding population distribution and density which, in turn, affect public exposure to project emissions. Additional factors affecting potential public health impact include existing air quality and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The proposed site is located about five miles west of Blythe in an area that has been designated for industrial development.

The proposed project would occupy parcels of unimproved land. In the vicinity of the project, land use is primarily agricultural. Directly east and south of the project site, almost 500 acres of lemons are cultivated, and citrus orchards dominate the area. The Blythe airport is about one mile to the west, and the Interstate 10 corridor is about one-quarter mile to the south. The proposed project would be located southwest of the existing Blythe Energy Project (BEP I).

As mentioned above, the location of sensitive receptors near the proposed site is an important factor in considering potential public health impacts. The nearest residence is about three-quarters of a mile to the southwest, north of Interstate 10 and south of Hobson Way. There are a few farm residences, primarily to the east and south, more than one mile from the site. The nearest residential area is an unincorporated area, called Nicholls Warm Springs (also known as Mesa Verde), located about 2.5 miles to the southwest. There are no sensitive receptor facilities such as schools, hospitals, daycare facilities, or convalescent centers within three miles of the site.

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into ambient air as well as the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants and associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced and localized exposure may be increased.

The locale is a desert climate with low precipitation (less than four inches annually), high temperatures with a wide daily range, and low relative humidity. About 42 percent of precipitation occurs from December through March, and is associated with winter storms from the Pacific Ocean. About 25 percent of precipitation occurs in July and August, and is associated with a monsoonal flow of moisture from the Pacific Ocean and the Gulf of California. Wind directions are predominantly from the southwest from April through September, and from the northeast the remainder of the year. This pattern is highly seasonable and is influenced by the southwest-northeast orientation of the Colorado River Valley.

Atmospheric stability is a measure related to turbulence, or the ability of the atmosphere to disperse pollutants due to convective air movement. Average monthly mixing heights (the height above ground level through which the air is well mixed and in which pollutants can disperse) range from 800 meters above ground level during winter to near 3000 meters in the summer. Winds are calm approximately 15 percent of the time. Staff’s **Air Quality** section presents more detailed meteorological data.

EXISTING AIR QUALITY

Ambient air quality data have not been measured in the Blythe area since 1992 (BEP 2002d, p. 7.7-40). The air quality monitoring data selected as most representative of the Blythe area was collected at Twentynine Palms, located 90 miles west-northwest of Blythe. There are very few sources of industrial pollutants in the Blythe area. No large stationary sources, other than the immediately adjacent BEP I, located approximately 1100 feet northeast and a Southern California Gas compressor facility located about 1.5 miles east-southeast, are sited within a three mile radius of the proposed site.

SITE CONTAMINATION

Site disturbances will occur during facility construction from excavation, grading, and earth moving. Such activities have the potential to adversely affect public health through various mechanisms, such as the creation of airborne dust, material being carried off-site through soil erosion, and uncovering buried hazardous substances.

A Phase I Environmental Site Assessment (ESA) performed for the site found the site not to be associated with any adverse health effects as a result of past activities at the site.

IMPACTS

PROJECT SPECIFIC IMPACTS

Potential risks to public health may occur during both project construction and operation.

Construction Impacts

Potential risks to public health during construction may be associated with exposure to toxic substances in contaminated soil disturbed during site preparation, as well as from heavy equipment operation. Criteria pollutant impacts from the operation of heavy equipment and particulate matter from earth moving are examined in staff's **Air Quality** analysis.

As described above and in the **Waste Management** section, the Phase I ESA reported no evidence of widespread site contamination. Therefore, no significant toxics-related public health impacts are anticipated from earth moving due to project construction.

The operation of heavy construction equipment will result in toxic emissions from diesel-fueled engines. Diesel exhaust is a complex mixture of many constituents that could cause adverse health impacts. However, the area of potential impact tends to be very close to the sources, due to the low height of the exhaust stacks. As noted above, the nearest residence is about three-quarters of a mile to the southwest, with a few farm residences located more than one mile from the site. The nearest residential area is located about 2.5 miles to the southwest. Thus, staff does not expect there to be any impact to members of the public from the toxic constituents of diesel equipment exhaust.

Operation Impacts

Emissions Sources

The emissions sources at the proposed BEP II include two combustion turbine generators, two supplementally fired heat recovery steam generators that supply steam to a steam turbine generator, a main cooling tower and an evaporative condenser or cooling tower for inlet chilling (BEP II 2002d, 2002g). During operation, potential public health risks are related to natural gas combustion emissions from the gas turbines and duct burners and noncombustion emissions from the cooling tower.
As noted earlier, the first step in a health risk assessment is to identify potentially toxic compounds that may be emitted from the facility. PUBLIC HEALTH Table 1 lists combustion-related toxic emissions from the turbines and supplementally-fired steam generators and shows how each contributes to the health risk analysis. For example, the first row shows that acetaldehyde may have cancer and chronic (long-term) noncancer health effects, but not acute (short-term) effects.

Noncriteria emissions from the cooling tower originate from contaminants in the cooling source water that become entrained in liquid water droplets emitted as cooling tower drift. PUBLIC HEALTH Table 2 lists these substances and shows how each contributes to the health risk analysis.

PUBLIC HEALTH Table 1
Natural Gas Combustion Emissions and Associated Potential Health Impacts

Substance	Cancer	Chronic Noncancer	Acute Noncancer
Acetaldehyde	✓	✓	
Ammonia		✓	✓
Benzene	✓	✓	✓
1,3-Butadiene	✓		
Formaldehyde	✓	✓	✓
Napthalene		✓	
PAHs	✓		
Propylene oxide	✓	✓	✓
Toluene		✓	
Xylene		✓	✓

Source: AFC Table 7.8-3, using reference exposure levels and cancer unit risks from the CAPCOA Air Toxics "Hot Spots" Program revised 1992 Risk Assessment Guidelines, October 1993

PUBLIC HEALTH Table 2
Cooling Tower Emissions and Associated Potential Health Impacts

Substance	Cancer	Chronic Noncancer	Acute Noncancer
Arsenic	✓	✓	✓
Cadmium	✓	✓	
Copper		✓	✓
Lead	✓	✓	
Manganese		✓	
Mercury		✓	✓
Nickel	✓	✓	✓
Selenium		✓	✓
Zinc		✓	

Source: AFC Table 7.8-3, using reference exposure levels and cancer unit risks from the CAPCOA Air Toxcis "Hot Spots" Program Revised 1992 Risk Assessment Guidelines, October 1993

The BEP II will use high efficiency drift eliminators which limit the amount of drift loss to approximately 0.0006 percent of the circulating water rate, resulting in a drift rate of about 0.9 gallon per minute (BEP 2002d, page 7.7-11). This amount of water lost as liquid from the cooling towers is in contrast to the amount of water evaporated as steam, estimated to be from 1500 to 1800 gallons per minute, depending on ambient temperatures (BEP 2002d, Appendix 7.7-C). Steam emitted from the cooling towers is distilled water, and will not contain contaminants. Similarly, drift eliminators on the inlet air chiller cooling tower will reduce the cooling tower mist to approximately 0.2 gallons per minute based on a loss of 0.001 percent.

The drift eliminators must be properly installed and maintained in order to achieve efficient operation over the life of the facility. Following installation, proper maintenance includes periodic inspection and repair or replacement of any components found to be broken or missing. Staff has proposed Condition of Certification PH–1 to ensure the inspection and maintenance of drift eliminators.

Emissions Levels and Concentrations

Once potential emissions are identified, the next step is to quantify them by conducting a "worst case" analysis.

Estimates of emissions on an hourly and annual basis are required to calculate acute (short-term) and cancer and chronic (long-term) noncancer health effects. BEP II Table 7.7-3 shows maximum fuel use for the gas turbines and duct burners (BEP 2002d, p. 7.7-4). The maximum fuel use is combined with the emission factor for each toxic air contaminant to estimate maximum hourly and annual emissions. Emission factors are estimates of the amounts of toxic substances released per unit of fuel burned from data in the California Air Toxic Emission Factors database maintained by the California Air Resources Board as well as from the U.S. Environmental Protection Agency (U.S. EPA 2000). Emission factors for metals from the cooling tower are derived from analyses of metals concentrations in the water used for cooling.

The next step in the health risk assessment process is to estimate the maximum ambient concentrations of toxic substances. This is accomplished by estimating the maximum impact under a variety of operating conditions and using a screening air dispersion model that assumes conditions resulting in maximum impacts. The screening analysis uses U.S. EPA approved ISCST3 dispersion modeling program (please see staff's **Air Quality** section for a detailed discussion of the modeling methodology).

Finally, ambient concentrations are combined with RELs and cancer unit risk factors to estimate health effects which might occur from exposure to facility emissions. Exposure pathways, or ways in which people might come into contact with toxic substances, include inhalation, dermal (through the skin) absorption, soil ingestion, and mother's milk.

The above method of assessing health effects is described in the California Air Pollution Control Officers Association (CAPCOA) Air Toxics "Hot Spot" Program Revised 1992 Risk Assessment Guidelines (October 1993), and results in the following health risk estimates.

Acute and Chronic Noncancer Hazard

The acute hazard index at the point of maximum impact for substances that could cause short-term health effects is 0.013 (PUBLIC HEALTH Table 3). This means that the air concentration to which the public is exposed is about 77 times lower than an air concentration that is considered safe for all parts of the population, including sensitive subgroups. With the acute hazard index well under the significance level of 1.0, no short-term health effects are expected from routine plant operation.

The chronic hazard index at the point of maximum impact for substances that could cause long-term health effects is 0.002 (PUBLIC HEALTH Table 3) which means that the air concentration to which people are exposed is about 455 times lower than the "safe" level for all parts of the population. The chronic hazard index is well under the safe level of 1.0, culminating in no chronic health effects. Further, all maximum hazard locations are in undeveloped areas, distant from sensitive receptors.

PUBLIC HEALTH Table 3
Facility Hazard/Risk

Type of Hazard/Risk	Hazard Index/Risk	Significance (Safe) Level
Acute Noncancer	0.013	1.0
Chronic Noncancer	0.002	1.0
Individual Cancer	0.298×10^{-6}	10.0×10^{-6}

Source: BEP 2002a AFC

Cancer Risk

As shown in PUBLIC HEALTH Table 3, total worst-case individual cancer risk is estimated to be 0.298 in one million. This is the risk at the location where long-term pollutant concentrations are calculated to be the highest and is thirty-three times lower than the significance level of ten in one million.

Cooling Tower

In addition to being a source of potential toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling tower, including Legionella. Legionella is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in man-made water systems. It is the principal cause of legionellosis, otherwise known as legionnaires' disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water. Untreated or inadequately treated cooling systems, such as industrial cooling towers and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of legionellosis.

Legionella can grow symbiotically with other bacteria and can infect protozoan hosts. This provides Legionella with protection from adverse environmental conditions, including making it more resistant to water treatment with chlorine, biocides, and other disinfectants. Thus, if not properly maintained, cooling water systems and their components can amplify and disseminate aerosols containing Legionella.

The U.S. Environmental Protection Agency (U.S. EPA) published an extensive review of Legionella in a human health criteria document (EPA 1999). The U.S. EPA noted that Legionella may propogate in biofilms (collections of microorganisms surrounded by slime they secrete, attached to either inert or living surfaces) and that aerosol-generating systems such as cooling towers can aid in the transmission of Legionella from water to air. The U.S. EPA has inadequate quantitative data on the infectivity of Legionella in humans to prepare a dose-response evaluation. Therefore, sufficient information is not available to support a quantitative characterization of the threshold infective dose of Legionella. Thus, the presence of even small numbers of Legionella bacteria presents a risk - however small - of disease in humans.

In 2000, the Cooling Technology Institute (CTI) issued its own report and guidelines for the best practices for control of Legionella (CTI 2000). The CTI found that 40-60 percent of industrial cooling towers tested was found to contain Legionella. It estimated that more than 4,000 deaths per year are believed to occur from Legionellosis (from all sources, not limited to industrial cooling towers), but only about 1,000 are reported. The CTI listed no reference or supportive data for this assertion, however.

To minimize the risk from Legionella, the CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use of high-efficiency mist eliminators on cooling towers, and the overall general control of microbiological populations.

Good preventive maintenance is very important in the efficient operation of cooling towers and other evaporative equipment (ASHRAE 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate, maintaining mechanical components in working order, and maintaining an effective water treatment program with appropriate biocide concentrations. Staff notes that most water treatment programs are designed to minimize scale, corrosion, and biofouling and not to control Legionella.

The efficacy of any biocide in ensuring that bacterial and in particular Legionella growth, is kept to a minimum is contingent upon a number of factors including but not limited to proper dosage amounts, appropriate application procedures and effective monitoring. Staff has proposed Condition of Certification **PH-2** that would require the project owner to prepare and implement a biocide and bacterial control program. The program, which would have to be approved by Staff, would ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is conducted to remove bio-film buildup. Staff believes that with the use of an aggressive antibacterial program coupled with routine monitoring and bacteria removal, the chances of Legionella growing and dispersing would be reduced to insignificant.

CUMULATIVE IMPACTS

Elevated concentrations of toxic air contaminants from stationary sources tend to be quite localized, and cumulative risks are likely to occur only when multiple facilities with substantial low-level emissions are immediately adjacent to, or very close to, one another. The closest major stationary sources are BEP I and the Southern California compressor station.

Conditions are not conducive for the potential mingling of the emissions from the compressor station with BEP I and BEP II. This is because of the extended distance and differences in elevation between the station and BEP II and the general prevailing wind direction. Consequently, emissions for the compressor station were not included in the cumulative health risk assessment. Instead, the risk assessment was performed using emission calculations from only BEP I and BEP II. The cumulative excess lifetime cancer risk is estimated to be 0.73 in a million and the cumulative chronic and acute noncancer hazard indices are 0.005 and 0.027 respectively. The levels are well below their significance levels and staff does not expect any cumulative health impacts to be significant.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is more than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this PSA). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

Based on the **Public Health** analysis staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project and, therefore, there are no public health environmental justice issues related to this project.

FACILITY CLOSURE

As noted in the introduction to this section, the scope of staff's public health analysis is limited to routine releases of harmful substances to the environment. During either temporary or permanent facility closure, the major concern would be from accidental or nonroutine releases from either hazardous materials or wastes which may be onsite. These are discussed in the sections on **Hazardous Materials** and **Waste Management**, respectively. During temporary closure (periods greater than those required for normal maintenance), it is unlikely that there would be any routine releases of harmful substances to the environment, since the facility would not be operating. For permanent closure, the only routine emissions would be related to facility demolition or dismantling, such as exhaust from heavy equipment or fugitive dust emissions. These would be subject to closure conditions adopted by the Energy Commission once a closure plan is received from the project owner.

MITIGATION

Noncriteria emissions from the proposed project are determined by many factors such as mode of facility operation, type of pollution control equipment, and type of fuel used. Please refer to the **Air Quality** section of this document for a detailed description and analysis of air pollution mitigation measures. Additionally, staff has proposed two Conditions of Certification to mitigate potential health impacts from cooling tower drift.

COMPLIANCE WITH APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff concludes that construction and operation of BEP II will be in compliance with all applicable LORS regarding long-term and short-term project impacts.

CONCLUSIONS AND RECOMMENDATIONS

Staff has analyzed potential public health risks associated with construction and operation of the BEP II. With implementation of the conditions of certification included herein, as noted, staff does not expect there to be any significant adverse cancer, or short- or long-term noncancer health effects from project emissions.

CONDITION OF CERTIFICATION

PH-1: The project owner shall perform a visual inspection of the cooling tower drift eliminators once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to initial operation of the project, the project owner shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminator and certify that the installation was performed in a satisfactory manner. The CPM may, in years 5 and 15 of project operation, require the project owner to perform a source test of the PM_{10} emissions rate from the cooling tower to verify continued compliance with the vendor guaranteed drift rate.

Verification: The project owner shall include the results of the annual inspection of the cooling tower drift eliminators and a description of any repairs performed in the next required annual compliance report. The initial compliance report will include a copy of the cooling tower vendor's field representative's inspection report of the drift eliminator installation. If the CPM requires a source test as specified in Public Health-1, the project owner shall submit to the CPM for approval a detailed source test procedure 60 days prior to the test. The project owner shall incorporate the CPM's comments, conduct testing, and submit test results to the CPM within 60 days following the tests.

PH-2: The project owner shall develop and implement a cooling tower Biocide Use, Biofilm Prevention, and Legionella Control Program to ensure that cooling tower bacterial growth is controlled. The Program shall be consistent with CEC's guidelines or the Cooling Tower Institute's guidelines for control of Legionella.

Verification: At least 30 days prior to the commencement of cooling tower operations, the Project Owner shall provide the Biocide Use, Biofilm Prevention, and Legionella Control Program to the CPM for review and approval.

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ATTACHMENT A - CRITERIA POLLUTANT HEALTH EFFECTS

OZONE (O_3)

Ozone is formed when reactive organic gases are mixed with nitrogen oxides in the presence of sunlight. Heat speeds up the reaction, typically leading to higher concentrations in the summer months. Ozone is a colorless, very reactive gas which oxidizes other materials. Oxidation damages living cells and tissues by altering their protein, lipid, and carbohydrate components or products. Such damage leads to dysfunction and death of cells in the lung and in other internal tissues.

The U.S. EPA revised the federal ozone standard on July 18, 1997 (62 Fed. Reg. 38856), based on new health studies which became available since the standard was last revised in 1979. These new studies showed that adverse health effects occur at lower ambient concentrations over longer exposure times than those reflected in the previous standard, which was based on acute health effects associated with heavy exercise and short-term exposures. The U.S. EPA's proposed ozone rule lists health effects which have been attributed to result from short-term (one to three hours) and prolonged (six to eight hours) exposure to ozone (61 Fed. Reg. 65719). However, a 1999 federal court ruling blocked implementation of the ozone 8-hour standard. EPA has asked the U.S. Supreme Court to reconsider that decision.

Acute health effects induced by short-term exposures include transient reductions in pulmonary function, and transient respiratory symptoms including cough, throat irritation, chest pain, nausea, and shortness of breath with associated effects on exercise performance. Other health effects associated with short-term or prolonged O_3 exposures include increased airway responsiveness (a predisposition to bronchoconstriction caused by external stimuli such as pollen and dust), susceptibility to respiratory infection by impairing lung defense mechanisms, increased hospital admissions and emergency room visits, and transient pulmonary inflammation.

Generally, groups considered especially sensitive to the effects of air pollution include persons with existing respiratory diseases, children, pregnant women, and the elderly. However, controlled exposure data on people in clinical settings have indicated that the population at greatest risk of acute effects from ozone exposures are children and adults engaged in physical exercise. Children are most at risk because they are active outside, playing and exercising, during the summer when ozone levels are at their highest. Adults who are outdoors and engaging in activities involving heavy levels of exertion during the summer months are also among those most at risk. Exertion increases the amount of O_3 entering the airways and can cause O_3 to penetrate to peripheral regions of the lung where lung tissue is more likely to be damaged. These individuals, as well as those with respiratory illnesses, such as asthma, can experience a reduction in lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion.

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless gas which is a product of inefficient combustion. It does not persist in the atmosphere, but is quickly converted to carbon dioxide. However, it can reach high levels in localized areas, or "hot spots".

CO reduces the oxygen carrying capacity of the blood, thereby disrupting the delivery of oxygen to the body's organs and tissues. Persons sensitive to the effects of carbon monoxide include those whose oxygen supply or delivery is already compromised. Thus, groups potentially at risk to carbon monoxide exposure include persons with coronary artery disease, congestive heart failure, obstructive lung disease, vascular disease, anemia, the elderly, newborn infants, and fetuses (CARB 1989, p. 9). In particular, people with coronary artery disease were found to be especially at risk from carbon monoxide exposure (CARB 1989, p. 9). Tests conducted on patients with confirmed coronary artery disease indicated that exposure to low levels of carbon monoxide during exercise produced significant cardiac effects. These included earlier onset of chest pain (angina) and electrocardiographic changes indicative of effects on the heart muscle (CARB 1989, p. 6). Such changes can limit the ability of patients with coronary artery disease to exert themselves even moderately. Therefore, the statewide carbon monoxide one hour and eight hour standards were adopted in part to prevent aggravation of chest pain. Additionally, however, the standards are intended to prevent decreased exercise tolerance in persons with peripheral vascular disease and lung disease, impairment of central nervous system functions, and increased risk to fetuses (Title 17, Cal. Code Regs., §70200).

PARTICULATE MATTER (PM)

Particulate matter is a generic term for particles of various substances, which occur as either liquid droplets or small solids of a wide range of sizes. Particles with the most potential to adversely affect human health are those less than 10 micrometers (millionths of a meter) in diameter (known as PM10), which may be inhaled and deposited within the deep portions of the lung (PM10). PM may originate from anthropogenic or natural sources such as stationary or mobile combustion sources or windblown dust. Particles may be emitted directly to the atmosphere or result from the physical and chemical transformation of gaseous emissions such as sulfur oxides, nitrogen oxides, and volatile organic compounds. PM10 may be made up of elements such as carbon, lead, and nickel; compounds such as nitrates, organics, and sulfates; and complex mixtures such as diesel exhaust and soil fragments. The size, chemical composition, and concentration of ambient PM10 can vary considerably from area to area and from season to season within the same area.

PM10 can be grouped into two general sizes of particles, fine and coarse, which differ in formation mechanisms, chemical composition, sources, and potential health effects. Fine-mode particles are those with a diameter of 2.5 micrometers or less (PM2.5), while the coarse-mode fraction of PM consists of particles ranging from 10 micrometers down to 2.5 micrometers in diameter.

Coarse-mode PM10 is formed by crushing, grinding, and abrasion of surfaces, and in the course of reducing large pieces of materials to smaller pieces. Coarse particles consist mainly of soil dust containing oxides of silicon, aluminum, calcium, and iron; as well as fly ash, particles from tires, pollen, spores, and plant and insect fragments. Coarse particles normally have shorter lifetimes (minutes to hours) and only travel over short distances (of less than tens of kilometers). They tend to be unevenly distributed across urban areas and have more localized effects than the finer particles.

PM2.5 is derived both from combustion by-products, which have volatilized and condensed to form primary PM2.5, and from precursor gases reacting in the atmosphere to form secondary PM2.5. Components include nitrates, organic compounds, sulfates, ammonium compounds, and trace elements (including metals) as well as elemental carbon such as soot. Major sources of PM2.5 are fossil fuel combustion by electric utilities, industry and motor vehicles, vegetation burning, and the smelting or other processing of metals. Dry deposition of fine mode particles is slow allowing such particles to often exist for long periods of time (of from days to weeks) in the atmosphere and travel hundreds to thousands of kilometers. They tend to be uniformly distributed over urban areas and larger regions and are removed from the atmosphere primarily by forming cloud droplets and falling out within raindrops.

The health effects of PM10 from any given source usually depend on the toxicity of its constituent pollutants. The size of the inhaled material usually determines where it is deposited in the respiratory system. Coarse particles are deposited most readily in the nose and throat area while the finer particles are more likely to be deposited within the bronchial tubes and air sacs, with the greatest percentage deposited in the air sacs. Until recently, PM10 particles had been considered to be the major fraction of airborne particulates responsible for various adverse health effects. The PM10 fraction is known to be capable of penetrating the thoracic and alveolar regions of the human and animal lungs. The PM2.5 fraction, however, was found to pose a significantly higher risk for health. This is due to their size and associated deposition and retention characteristics in the respiratory tract, enabling it to penetrate and deposit within the deeper alveolar regions of the lung. The following aspects of PM2.5 deposition all contribute to the more serious health effects attributed to smaller particles:

- The deposition of PM2.5 favors the periphery of the lungs, which is especially vulnerable to injury for anatomical reasons.

- Clearance of the PM2.5 from within the deeper reaches of the lungs is a much slower process than from the upper regions. Consequently, the residence time is longer, implying longer exposure, and hence greater risk.

- The human anatomy further allows the penetration of the superficial tissues by PM2.5 and entry into the bodily circulation without much effort in the periphery of the lungs.

Many epidemiological studies have shown exposure to particulate matter capable of inducing a variety of health effects, including premature death, aggravation of respiratory and cardiovascular disease, changes in lung function and increases in existing respiratory symptoms, effects on lung tissue structure, and impacts on the body's respiratory defense mechanisms. The underlying biological mechanisms are still poorly understood. Based on their review of a number of these epidemiological studies (as published after 1987 when the federal standards were revised), together with suggestion of PM2.5 concentrations as a more reliable surrogate for the health impacts of the finer fraction of PM than PM10, the U.S. EPA concluded that the then-current standards were not sufficiently stringent to protect against significant effects in exposed humans. Therefore, federal PM standards were revised on July 18, 1997 (62 Fed. Reg. 38652) to add new annual and 24-hour PM2.5 standards to the existing annual and 24-hour PM10 standards. Taken together, these new standards were meant to provide additional protection against a wide range of PM-related health effects, including premature death, increased hospital admissions and emergency room visits, primarily among sensitive individuals such as the elderly, children and individuals with cardiopulmonary diseases such as asthma. Other impacts include decreased lung function (particularly in children and asthmatics), and alterations in lung tissue and structure.

California has also had 24-hour and annual standards for PM10 (CARB 1982, pp. 81, 84). These studies were aimed at establishing the PM10 levels capable of inducing asthma, premature death and bronchitis-related symptoms. They were set to protect against such impacts in the general population as well as sensitive individuals such as patients with respiratory disease, declines in pulmonary function, especially as related to children (Tit. 17, Cal. Code Regs., §70200). These standards were set to be more stringent than the federal standard, which the ARB regarded as inadequate for the protection desired (CARB 1991, p. 26).

On June 20, 2002, the ARB approved the adoption of a lower annual state standard for PM10, as well as a new annual standard for PM2.5 (CARB 2002). The new standards took effect on July 5, 2003. The 24-hour PM10 standard was not changed. The standards were established to prevent excess death, illnesses such as respiratory symptoms, bronchitis, asthma exacerbation, and cardiac disease, and restrictions in activity from short- and long-term exposures (Title 17, Cal. Code Regs., §70200).

NITROGEN DIOXIDE (NO_2)

Nitrogen dioxide is formed either directly or indirectly when oxygen and nitrogen in the air combine during combustion processes. It is a relatively insoluble gas which is able to penetrate deep into the lungs, its principal site of toxicity. Its toxicity is thought to be due to its capacity to initiate free radical reactions and to oxidize cellular proteins and other biomolecules (CARB 1992, Appendix A, p. 4).

Sublethal exposures in animals produce inflammation and various degrees of tissue injury characteristic of oxidant damage (Evans in CARB 1992, Appendix A, p. 5). The changes produced by low-level acute or subchronic exposure appear to be reversible when animals are allowed to recover in clean air.

Health effects of particular concern in relation to low-level nitrogen dioxide exposure include: (1) effects of acute exposure on some asthmatics and possibly on some persons with chronic bronchitis, (2) effects on respiratory tract defenses against infection, (3) effects on the immune system, (4) initiation or facilitation of the development of chronic lung disease, and (5) interaction with other pollutants (CARB 1992, Appendix A, p. 5).

Several groups which may be especially susceptible to nitrogen dioxide related health effects have been identified (CARB 1992, Appendix A, p. 3). These include asthmatics, persons with chronic bronchitis, infants and young children, cystic fibrosis and cancer patients, people with immune deficiencies, and the elderly.

Studies using controlled brief exposures on sensitive groups have shown an increase in bronchial reactivity or airway responsiveness of some asthmatics, and decreased lung function in some patients with chronic obstructive lung disease (CARB 1992, Appendix A, p. 2). In general, bronchial hyperreactivity (an exaggerated tendency of the airways to constrict) is markedly greater in asthmatics than in nonasthmatics upon exposure to respiratory irritants (CARB 1992a, p. 107). At exposure concentrations relevant to the current one hour ambient standard, there appears to be little, if any, effect on respiratory symptoms of asthmatics (CARB 1992a, p. 108).

SULFUR DIOXIDE (SO_2)

Sulfur dioxide is formed when any sulfur-containing fuel is burned. SO_2 is highly soluble and consequently absorbed in the moist passages of the upper respiratory system. Exposure to sulfur dioxide can cause changes in lung cell structure and function that adversely affect a major lung defense mechanism known as muco-ciliary transport. This mechanism functions by trapping particles in mucus in the lung and sweeping them out via the cilia (fine hair-like structures) also in the lung. Slowed mucociliary transport is frequently associated with chronic bronchitis.

Exposure to sulfur dioxide can produce both short- and long-term health effects. Therefore, California has established sulfur dioxide standards to reflect both short- and long-term exposure concerns. Based on controlled exposure studies of human volunteers, investigators have found that asthmatics comprise the group most susceptible to adverse health effects from exposure to sulfur dioxide (CARB 1994, p. V-1).

The primary short-term effect is bronchoconstriction, a narrowing of the airways which results in labored breathing, wheezing, and coughing. The short-term (one hour) standard is based on bronchoconstriction and associated symptoms (such as wheezing and shortness of breath) in asthmatics and is designed to protect against adverse effects from five to ten minute exposures. In the opinion of the California Office of Environmental Health Hazard Assessment, the short-term ambient standard is likely to afford adequate protection to asthmatics engaged in short periods of vigorous activity (CARB 1994, Appendix A, p. 16).

Longer-term exposure is associated with an increased incidence of respiratory symptoms (e.g., coughing and wheezing) or respiratory disease, decreases in pulmonary function, and an increased risk of mortality (CARB 1991a, p. 12). The long-term (24 hour) standard is based upon increased incidence of respiratory disease and excess mortality. The standard includes a margin of safety based on epidemiological studies which have shown adverse respiratory effects at levels slightly above the standard. Some of the studies indicate a sulfur dioxide threshold for effects, whereby "no adverse effects" are expected from exposures to concentrations at the state standard (Ibid.).

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SOCIOECONOMICS

Amanda Stennick

INTRODUCTION

The California Energy Commission (Energy Commission) staff's socioeconomics impact analysis evaluates several areas in which the project may induce changes including community services and/or infrastructure and related community issues such as environmental justice and facility closure. Direct, indirect, and cumulative impacts are included in the evaluation. This analysis discusses the potential impacts of the proposed Blythe Energy Project Phase II (BEP II) on local communities, community resources, and public services, pursuant to Title 14, California Code of Regulations, Section 15131, and examines the project's compliance with applicable laws, ordinances, regulations and standards.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

California Government Code, sections 65995-65997, as amended by SB 50 (Stats. 1998, ch. 407, sec. 23), states that public agencies may not impose fees, charges or other financial requirements to offset the cost for school facilities. The relevant provisions restrict fees for the development of commercial and industrial space to an initial maximum of $0.31 per square foot of "chargeable covered and enclosed space to be adjusted for inflation". The maximum fee is currently $.34 per square foot.

ENVIRONMENTAL SETTING AND IMPACTS ANALYSIS

BEP II would be located in eastern Riverside County approximately 5 miles west of the City of Blythe and two miles northeast of the unincorporated community of Mesa Verde. Blythe is about 171 miles east of the City of Riverside, on the Arizona border. BEP II will be located on a 76-acre tract adjacent to the current Blythe Energy Project (BEP I) that was approved by the California Energy Commission on March 21, 2001. The BEP I is currently under construction and is owned by Wisvest Corporation.

Staff reviewed the BEP II AFC, Vol. I, July 2002, Section 7.6, Socioeconomics regarding potential impacts to community services and infrastructure (i.e., employment, housing, schools, utilities, emergency and other services), and environmental justice. Based on staff's use of the socioeconomic data provided and referenced from governmental agencies, trade associations, and staff's independent analysis, staff agrees with the Application for Certification's (AFC) socioeconomic analysis and conclusions.

Staff reviewed the BEP II AFC, Vol. I, July 2002, Sections 7.13, Water Resources and 7.14 Agriculture and Soils and subsequest responses to Data requests regarding water use and removal of agricultural land from production. The proposed Water Conservation Offset Plan (WCOP) currently proposed is voluntary and provides insufficient detail for staff to determine how it will impact the region's agricultural community. Staff requires information on the location of acreage being fallowed, number of acres, type of crop, and number of workers associated with the crops and acreage before an assessment of the WCOP's environmental justice impact can be prepared.

For housing, staff uses a vacancy rate of five percent or less of permanent available housing, and for environmental justice, staff uses a threshold of greater than 50 percent for minority/low-income population in the affected area. Criteria for subject areas such as fire protection, water supply and wastewater disposal are analyzed in other sections of this staff assessment. Impacts to school enrollment and capacities are determined based on the potential for in-migration of construction workers and their school-age children. Impacts on medical services, law enforcement, or community cohesion are based on subjective judgments or input from local and state agencies. Typically, greater non-local employment has the potential to result in significant impacts.

POPULATION

The historical and current populations of Blythe and Riverside County are shown in **SOCIOECONOMICS Table 1**.

SOCIOECONOMICS Table 1
Historical and Current Populations

	Historical Population			
AREA	**1990**	**2000**	**Percent Change**	**Annual Growth Rate %**
California	29,760,021	33,871,648	13.8	1.3
Riverside County	1,170,413	1,545,387	32.0	2.8
City of Riverside	226,505	255,166	12.7	1.2
City of Blythe excluding correction facilities	8,428	12,155	44.2	3.2

Source: U. S. 2000 Census

SCHOOLS

The Palo Verde Unified School District serves the BEP II. The school district is composed of three elementary schools, one middle school, one high school, and one continuation school (see **SOCIOECONOMICS Table 2**). The community also has a two-year community college and two private schools: The Zion Lutheran School and the Escuela De La Raza Unida School. Data obtained from the California Department of Education's website states that for the 2002-2003 school year, District enrollment was 3,686 (DOE 2003). **SOCIOECONOMICS Table 2** shows that for the 1998-1999 school year, enrollment was about the same. According to the District, enrollment has been declining at the rate of one to two percent per year since 1995. Thus, District schools are able to accommodate additional students.

The Palo Verde Unified School District experienced its peak enrollment in the 1994-1995 school year at 4,050 students. Since that time, school enrollment has declined approximately 1.5 percent annually. Current enrollment is about 3,623 students.

Construction of the proposed project is not expected to result in significant population changes for the school system as most of the construction workers are expected to commute to the work site or take up temporary housing in the area. The operation of the BEP II will require a small work force of 20 employees. Therefore, if necessary, the Palo Verde Unified School District should be able to absorb additional students due to construction and operation at the BEP II.

If the Palo Verde Unified School district should require additional facilities, the funding would be through either property taxes or statutory facility fees. The Palo Verde Valley Unified School District has in place an impact fee of $0.31 per square foot for new construction of commercial/industrial buildings.

SOCIOECONOMICS Table 2
PALO VERDE UINIFIED SCHOOL DISTRICT, ENROLLMENT AND CAPACITY

Schools	Enrollment 1998-1999	Enrollment Capacity	Percent Capacity
ELEMENTARY			
Felix J. Appleby	565	745	75.8
Ruth Brown	635	780	81.4
Margaret White	625	680	91.9
Sub Total	1,815	2,225	82.8
Middle School			
Blythe Middle School	775	993	78.0
High School			
Palo Verde High School	1,015	1,140	89.0
Twin Palms Continuation High School	85	100	85.0
Grade 1-12 Total	3,700	4,438	83.4
College			
Community College	1,250	N/A	

Source: BEP 1999a, AFC.

EMPLOYMENT

The BEP II will require a pool of skilled laborers. As shown in **SOCIOECONOMICS Table 3**, Riverside County has a substantial skilled labor force from which to draw.

SOCIOECONOMICS Table 3
Available Labor By Skill In Riverside County, 1999 To 2006

Occupational Title	Annual Averages 1999	Annual Averages 2006	Percent Change
Carpenters	7380	10,100	36.9
Masons and Related Workers	3,050	4,070	33.4
Painters and Related Workers	1,430	1,900	32.9
Metal Workers	360	460	27.8
Electricians	2,160	2,840	31.5
Welders	870	1,130	29.9
Excavators	420	550	31.0
Graders	610	760	24.6
Industrial Truck Operator	1,270	1,610	26.8
Operating Engineers	760	960	26.3
Helpers, laborers	21,300	27,580	29.3
Pipefitters	1,620	2,120	30.9
Administrative Services Managers	1,180	1,480	25.4
Mechanical Engineers	510	700	37.3
Electrical Engineers	440	590	34.1
Engineering Technicians	2,260	2,940	30.1
Plant and System Operators	350	440	25.7

Source: Employment Development Department Riverside County

The AFC estimates that project construction activity will occur over 20 months. The labor force required for construction of the project includes boilermakers, carpenters, electricians, ironworkers, laborers, millwrights, operators, pipefitters and others. The employed force would include both skilled and non-skilled workers. Based on occupational employment projections by the Employment Development Department (see **SOCIOECONOMICS Table 3**), there are enough skilled laborers for project construction.

The labor force for construction of BEP II is expected to peak in the 12th month after the start of construction at 387 workers (see **SOCIOECONOMICS Table 4**). If additional workers are required, the project could draw from adjoining areas such as Las Vegas, Yuma, and Phoenix. Therefore, staff believes that sufficient workers for construction of the BEP II are available within the general area. Most of the workforce will be within a one-way commute time of two hours from the plant site. The demand for skilled laborers should not result in a community labor shortage.

During operation of the project, about 20 permanent workers will be needed to maintain and operate the project (12 to 14 operating technicians, 3 to 4 maintenance technicians and 3 to 4 administrators). Staff does not expect the number of employees required for operation of BEP II to cause a significant impact to the local labor force. There is no information in the Monthly Compliance Reports for BEP I that would indicate a labor shortage during construction.

BEP II is developing a voluntary water conservation offset program (WCOP) to offset its ground water use. Energy Commission water staff are reviewing and analyzing the applicant's proposed program. The WCOP for BEP II involves fallowing a maximum of 900 acres of irrigated farmland in the Palo Verde Irrigation District. At this time, staff does not know the exact number or type of acreage that will be fallowed. Because of the lack of information from the applicant, staff cannot determine whether a significant impact to the farm labor, farm services, and farm supply sectors will occur or whether it could disproportionately impact the minority and low-income community of Mesa Verde.

HOUSING

The BEP II could cause a tight housing market during construction if a large number of the workers relocate to the area. However, Blythe has supported a labor force for the construction of two prisons, Ironwood State Prison, which opened in February 1994 and Chuckawalla Valley Prison, which opened in December 1988. During the construction of these projects there was a maximum of 250 to 300 construction workers involved (BEP 1999). There was no noticeable shortage of housing for these workers during construction. Many of the workers brought RVs with them and took advantage of the many RV parks in the area for housing during construction.

Data from the Department of Finance (DOF) show that in January 2001 there were about 595,682 total housing units in Riverside County, with a vacancy rate of 13.4 percent. For the same period of time, the DOF estimated about 4,840 total housing units in Blythe, with a vacancy rate of 16.1 percent. In addition, the Blythe area has 23 motels with about 1,100 rooms; over 300 mobile home spaces, over 600 RV spaces; and additional housing, condominiums, and apartments constructed since the construction of the two prisons.

There are an additional 78 motels within 65 miles of Blythe (Yahoo 2003), which would be approximately one hour or less commute for workers using these facilities. The combination of housing, apartments, motel/hotel rooms, and RV spaces available to non-local construction and operation workers for this project should be sufficient.

Those employees seeking long-term residences could take advantage of new housing development that has been occurring within the City. The long-term operations of the facility would result in only a small increase in population with only 20 full-time employees required to operate the facility.

SOCIOECONOMICS Table 4
Blythe II Energy Project Estimated Construction Staffing

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Insulation Workers										9	17	21	28	28	21	17	14	9	6	2
Boiler Makers						14	21	30	30	30	30	30	24	19	19	9	9	9	6	2
Masons		2	5	9	9	9	9	5	3	2	1	1	1	1	1	1	1	1	1	0
Carpenters	10	13	15	22	30	36	40	40	35	29	23	23	23	19	12	10	10	10	6	0
Electricians	4	4	8	8	14	28	28	33	38	43	47	57	47	42	36	24	14	14	10	8
Iron Workers	3	7	7	10	15	26	33	39	39	33	26	19	14	9	9	9	9	9	5	2
Laborers	14	20	20	26	31	33	38	38	38	33	33	34	33	24	19	19	14	14	8	4
Millwrights	0	0	0	5	5	8	8	11	11	14	14	14	9	9	9	8	8	8	6	4
Operating Engineers	4	6	8	11	11	13	13	15	17	17	17	18	17	11	9	9	5	5	4	2
Plasters	0	0	0	0	0	0	0	2	2	4	4	6	4	4	2	0	0	0	0	0
Pipefitters	4	8	10	10	17	19	26	36	50	64	83	93	99	93	82	57	28	24	15	8
Sheer-metal Workers	0	0	0	0	0	0	0	0	6	9	9	14	17	14	9	9	9	6	4	2
Sprinkler Fitters	0	0	0	0	0	0	0	1	1	1	1	4	8	11	8	4	2	2	1	1
Surveyors	2	2	3	4	4	4	4	4	4	4	4	4	4	4	2	2	1	0	0	0
Teamsters	0	0	0	1	1	2	2	2	2	2	2	2	2	2	2	2	1	0	0	0
Total BEP II Power Plant Manual Staff	41	62	76	106	137	193	222	256	276	294	311	340	330	290	240	180	125	111	72	35
Total BEP II Power Plant Contractor Staff	6	11	17	23	28	33	38	38	47	47	47	47	47	38	36	28	28	26	20	10
Total BEP II Power Plant Site Staff	47	73	93	129	165	225	260	294	323	341	358	387	377	328	276	208	153	138	92	45
BEP Staffing	276	208	153	137																
Total Both Projects	323	281	246	266	165	225	260	294	323	341	358	387	377	328	276	208	153	138	92	45

Source: BEP II 2002a, AFC.

There are an additional 78 motels within 65 miles of Blythe (Yahoo 2003), which would be approximately one hour or less commute for workers using these facilities. The combination of housing, apartments, motel/hotel rooms, and RV spaces available to non-local construction and operation workers for this project should be sufficient.

Those employees seeking long-term residences could take advantage of new housing development that has been occurring within the City. The long-term operations of the facility would result in only a small increase in population with only 20 full-time employees required to operate the facility.

One possible concern for short-term housing is during the winter season. The population in the Palo Verde Valley triples during the winter season due to visitors that are attracted to the area because of its warm climate. Because a majority of the individuals coming to the area during the winter season typically use motor homes, trailers, and campers for their accommodations, staff expects that any potential housing needs for the BEP II construction workforce can be met by the City of Blythe and surrounding areas.

PUBLIC SERVICES

Please refer to the section on **WORKER SAFETY AND FIRE PROTECTION** for a discussion of fire protection services, potential impacts, and proposed mitigation.

Electricity And Gas

The applicant proposes that the project will interconnect with the regional electric transmission grid at Western's Buck Boulevard Substation located within 1,600 feet of the BEP II power island. Natural gas would be supplied to the BEP II by the delivery pipeline currently being constructed as part of BEP I.

Water Supply and Agricultural Water

Construction of BEP I included three on-site wells to supply water for all power plant needs. The annual consumption of groundwater extracted from the three on-site wells was estimated at 3,000 acre-feet. BEP II will construct and operate one additional groundwater pumping well for its water supply and will construct one additional evaporation pond. The water for BEP I and BEP II will be supplied by on-site wells. As stated above, BEP II is proposing a WCOP to offset its ground water use.

Water staff has concluded that the proposed use of groundwater to cool the plant would cause a significant direct impact to the Palo Verde Irrigation District water supply and its users, and contribute to a significant cumulative impact to the State's Colorado River water supply and its users. This may have implications in terms of environmental justice and the loss of agricultural jobs in a minority and low income community. Additional information will be needed regarding how the WCOP will be implemented and enforced in order for staff to reach a definitive environmental justice conclusion in the FSA. For more information on water supply, see the **SOILS AND WATER RESOURCES** section of this Preliminary Staff Assessment.

Sewer

Wastewater from BEP II would be disposed through the existing BEP I septic tank and leach field system. In addition, the area has two wastewater treatment facilities. One located south of Blythe, about five miles from the BEP, and the other, an oxidation lagoon east of the Blythe airport that is used to treat airport wastewater. The BEP II will not impact either of these wastewater facilities, as the project will handle its wastewater and sewage treatment on-site during construction and operation (BEP II 2002). Please refer to the **WATER RESOURCES** section for a detailed discussion of wastewater disposal.

Law Enforcement

The Blythe Police Department provides law enforcement for the City of Blythe. The Department is located at 249 North Spring Street, about five miles from the power plant. The current police department has a staff of 25 law enforcement officers. The Department estimates that emergency response time to the project would be about three minutes. Non-emergency response would be about seven minutes.

The City of Blythe has mutual aide agreements with other law enforcement organizations in the community. This includes the Riverside County Sheriff's Department, located at 260 North Spring Street in Blythe about five miles from the site. The Blythe station has 18 sworn full-time law enforcement officers and handles emergency calls for county residents in the general Palo Verde Valley. The estimated normal response time for a patrol vehicle to the BEP II would be about ten minutes.

Other law enforcement services would be provided by the California Highway Patrol station located about five miles from the BEP II site at 430 South Broadway in Blythe.

The construction and operation of the project would not result in significant demands on law enforcement.

Hospitals and Medical Services

Palo Verde Hospital is located at 250 North 1st Street in Blythe, about five miles east of the BEP II site. The hospital is a 55-bed acute care facility and has 24-hour emergency room service, 23 physicians/surgeons, six dentists, four optometrists, four chiropractors, and one podiatrist.

If required, other medical services are available in the area. Located approximately 30 miles from the BEP II in Parker, Arizona is the La Paz Medical Center. This is a full service hospital with eight doctors on staff, 39 beds and 24 hour emergency service. The community of Quartzsite has a clinic that offers daytime services and is associated with the La Paz Medical Center. Other medical facilities are located approximately 70 miles from the site, the largest being the Yuma Regional Medical Center in Yuma, Arizona with 237 beds.

Staff believes these services are adequate to meet the medical service needs of the BEP II during construction and operation.

FINANCIAL

The City of Blythe and Riverside County schools and other special districts in the BEP II Tax Rate Area will receive property tax revenue from the BEP II property. A "Tax Rate Area" is a grouping of properties within a county wherein each parcel is subject to the taxing powers of the same combination of taxing agencies. The BEP II will undergo annual assessment at fair market value, and the property tax collected will be distributed exclusively to the taxing jurisdictions within the Tax Rate Area in which the facility is located.

The local community will also receive a small amount of revenue from sales taxes on equipment, and material and supplies purchased during construction. The applicant estimates that the cost for material and supplies for construction will be $60 million. Of this amount, the applicant estimates about $5 to $10 million in material and supplies will be purchased locally. Sales tax in Riverside County is 7.75 percent, of which Blythe would receive one percent. Therefore, the City of Blythe would realize between $3,875 and $7,750 in sales tax revenues from materials and supplies during the construction period.

Impacts from construction include economic gains as a direct result of locally purchased materials and supplies, and construction payroll spending. Indirect or secondary impacts from construction could include increased employment for local workers in other areas of service, such as wholesale and retail, transportation, entertainment, and other business services.

In the AFC, the applicant states that to maintain the BEP during its operating life will require major maintenance for the facility every 3 to 4 years at an estimated cost of $10 million. Approximately 15 percent, or $1.5 million of this would be spent locally.

Operation of the BEP II will result in 20 full-time employees. As stated in the AFC, an employee's annual salary will average about $50,000, and will result in an average annual operating payroll of $1.0 million.

ENVIRONMENTAL JUSTICE

For all siting cases, Energy Commission staff conducts an environmental justice screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in USEPA's National Environmental Policy Act (NEPA) Compliance Analysis" dated April 1998. The purpose of the screening analysis is to determine whether there exists a minority or low-income population within the potentially affected area of the proposed site.

Minority Populations

Minority populations, as defined by USEPA's guidance document, are identified where either:

∉ The minority population of the affected area is greater than fifty percent of the affected area's general population; or

∉ The minority population percentage of the area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis.

In 1997, the President's Council on Environmental Quality issued environmental justice guidance that defines minorities as individuals who are members of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black not of Hispanic origin; or Hispanic.

Low-Income Populations

According to USEPA's guidance document, low-income populations are identified with the annual statistical series poverty thresholds from the Census Bureau's Current Population Reports, Series P-60 on Income and Poverty. The Census Bureau uses a set of money income thresholds that vary by family size and composition to determine who is poor. The thresholds are used to determine which families are at, above, or below the poverty level. If the total income for a family or unrelated individuals falls below the relevant poverty threshold, then the family or unrelated individuals are classified as being below the poverty level. Poverty status is determined for all people except institutionalized people, people in military group quarters, and people in college dormitories. The official poverty thresholds do not vary geographically but are updated annually for inflation using the Consumer Price Index. The official poverty definition counts money income before taxes and does not include capital gains and non-cash benefits such as public housing, Medicaid, and food stamps. The poverty threshold in 2002 for a family of four (two adults and two related children under 18) was $18,244.

Potentially Affected Area

Energy Commission staff has identified the potentially affected area as a six-mile radius of the proposed site. As shown in **SOCIOECONOMICS FIGURE 1**, the population within this area totals 12,170. The people of color within this area total 7,216, or 59.29 percent of the total population. In addition, there are multiple census blocks with greater than 50 percent minority populations within the six-mile radius. Because the screening analysis shows a greater than 50 percent minority population within the six-mile radius, staff conducted an environmental justice analysis in the technical areas listed in the **Introduction**.

As shown in **SOCIOECONOMICS FIGURE 1,** BEP I and BEP II are located about two miles from Mesa Verde/Nicholls Warm Springs, a small, unincorporated residential and largely Spanish-speaking community in the Palo Verde Mesa. Residents of this community and Blythe actively participated in the workshops and hearings for BEP I. Some residents of Blythe became intervenors in BEP I. Although their concerns for the health and well-being of the community included air quality impacts, their primary concern was water usage by BEP I, which when combined with water usage proposed by BEP II will total 6,578 acre-feet per year from the local aquifer, or twice the amount of water used locally for agriculture. Although Energy Commission staff found no unmitigated impacts for BEP I, based on community concerns of air and water quality issues, intervenors in the BEP I proceeding filed an environmental justice complaint against the BEP I project with the Department of Energy's (DOE) Office of Civil Rights and Diversity.

Summary

Census 2000 shows that the data set "Population for Whom Poverty Is Determined" totals 9,933 persons. Of these, 2,046 persons, or 20.1 percent, are below the poverty level. The Guidance does not give a numerical threshold level for poverty as it does for minority. In the absence of a threshold, staff has used the greater than 50 percent threshold for poverty levels. However, a population that totals 20.1 percent below the poverty level indicates a high degree of poverty in the six-mile radius.

The minority population and low-income population within the six-mile radius are 59.29 percent and 20.1 percent, respectively. Based on the socioeconomic analysis, there are no significant, adverse socioeconomic impacts to housing, schools, public services, police, medial services, and fiscal resources. However, staff has concluded that the proposed use of groundwater to cool the plant would cause a significant direct impact to the Palo Verde Irrigation District water supply and its users, and contribute to a significant cumulative impact to the State's Colorado River water supply and its users. The WCOP proposed in conjunction with the project's water use may have implications in terms of local agricultural jobs and the project's impact regarding environmental justice.

CUMULATIVE IMPACTS

The total number of workers at the project site (BEP I and BEP II) would average 279 in the first four months of BEP II construction. BEP II would employ an average of 232 workers over an 18- to 22-month time period, with a peak construction workforce of 387 employed in the 12th month. **SOCIOECONOMICS Table 2** indicates that there is no shortage of available skilled construction workers for BEP I and BEP II. In addition, no housing shortages were identified for BEP I, and staff does not expect any housing shortage due to construction of BEP II.

FACILITY CLOSURE

The socioeconomic impacts of permanent facility closure will be evaluated at the time under the Energy Commission's facility closure process.

Any unexpected, temporary closure would not likely cause any significant environmental impacts on the affected area, because the likely result of a temporary closure would be reactivation of the power plant by the same or a new owner within a relatively short period of time. Personnel changes may occur if there is an ownership change, but socioeconomics impacts would not change significantly because the number of operating personnel would remain relatively the same.

Any unexpected, permanent closure of the BEP II is not likely to cause any significant socioeconomics impacts on the affected area, because facility closure impacts (i.e., dismantling) would be similar to construction impacts, and staff has found no significant socioeconomics impacts due to the construction of the project.

MITIGATION

Staff does not expect the proposed project to have significant adverse socioeconomic impacts to housing, schools, public services, police, medical services, and fiscal resources. Therefore, staff proposes no conditions except the condition that the applicant be required to pay the statutory school impact fees.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The BEP II, both directly and indirectly should not cause a significant adverse impact on the affected area's housing, schools, police, emergency services, hospitals, or utilities during construction or operation.

The BEP II should result in some benefits for Riverside County from property and sales tax. The City of Blythe may also benefit from the economic activity that may be generated by the purchase of services, manufactured goods and equipment from local businesses. For example, during construction the project is expected to result in purchases of goods and services in the community of approximately $5 to $10 million. During plant operation, local expenditures will be about $1.5 million every three to four years.

A potential problem could exist during construction of the BEP if the peak construction period occurs during the winter season. The population in the Palo Verde Valley triples during the winter season, which could result in a tight housing market. If construction starts in late fall this will result in a peak labor force during mid to late summer, which should ease any potential housing problem for the community.

The Applicant has proposed a voluntary Water Conservation Offset Plan (WCOP) to offset the project's use of Colorado River water pumped as groundwater. The plan would call for BEP II to fallow land that has been under agricultural use within the last five years to offset the project's annual use of approximately 3,300 acre-feet of Colorado River water pumped as groundwater from wells at the plant site. The information provided by the applicant indicates that a value of 4.2 acre-feet of water per acre of land fallowed would be used to calculate the number of acres that would need to be fallowed to offset the project's water use.

Implementation of the WCOP would result in changes to the agricultural use of some lands in the vicinity of the proposed project. However, the applicant has provided no information as to which currently cultivated lands might be fallowed. Therefore, staff cannot determine whether a significant impact to the farm labor, farm services, and farm supply sector will occur or whether it would disproportionately impact the minority and low-income population of Mesa Verde. In order to complete the Final Staff Assessment, the applicant will need to provide full details on the proposed fallowing of croplands.

RECOMMENDATIONS

For the area of socioeconomics, staff recommends that should the Commission approve the BEP II, the proposed condition of certification should be adopted. Additional information will be needed regarding how the WCOP will be implemented and enforced in order for staff to reach a definitive conclusion with regards to environmental justice in the FSA.

SOCIOECONOMIC DATA AND INFORMATION - TABLE 2	
Project Capital Costs	
Estimate of Locally Purchased Materials	
Construction	$5-10 million annually
Operation	$1.5 million every three to four years
Existing /Projected Unemployment Rates	5.5% / 5.2%
Percent Minority Population (6 mile radius)	59.29%
Percent Poverty Population (6 mile radius)	20.1%

PROPOSED CONDITIONS OF CERTIFICATION

SOCIO-1 The project owner shall pay the statutory school impact development fee as required at the time of filing for the "in-lieu" building permit.

Verification: The project owner shall provide proof of payment of the statutory development fee to the Compliance Project Manager (CPM) in the next Monthly Compliance Report following the payment.

REFERENCES

BEP 1999. Application for Certification, Blythe Energy Project (99-AFC-8). Filed with the California Energy Commission, December 9, 1999.

BEP II 2002. Application for Certification, Blythe Energy Project (02-AFC-1). Filed with the California Energy Commission, July 3, 1999.

California Energy Commission Final Staff Assessment Blythe I. **SOCIOECONOMICS.** December 2000.

California Department of Education website. http://data1.cde.ca.gov/dataquest/

M. Cubed. Socioeconomic Assessment of the Proposed Palo Verde Irrigation District Land Management, Crop Rotation and Water Supply Program. Final Report, September 30, 2002. Prepared for Palo Verde irrigation District.

State of California, Employment Development Department, Labor Market Information Division. Projections – June 1998. Table 6, Occupational Employment Projections 1995 – 2002. www.clamis.cahwet.gov.

U.S. Census Bureau 2000. Internet Website, www.census.gov

Yahoo! Yellow Pages 2000a. website http://yp.yahoo.com.

SOCIOECONOMICS - FIGURE 1

Blythe Power Project - Census 2000 Minority Population by Census Block - Six Mile Buffer

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2003, Census 2000 PL 94-171 Data - Matrix PL2

SOIL AND WATER RESOURCES

Richard Sapudar, Linda Bond, Mark Lindley, and Jim Schoonmaker

INTRODUCTION

SUMMARY

Staff has determined the proposed use of Colorado River water pumped as groundwater by the BEP II project to have associated unmitigated significant direct and cumulative impacts, and does not conform to applicable LORS. Staff has found the project will have a significant direct impact and potentially significant cumulative impact to the PVID water supply and its users, and a significant cumulative impact to the State's Colorado River water supply. The use of Colorado River water pumped as groundwater has been found to be inconsistent with the California Constitution, the Water Code, and State water policies that require the State's water supply be conserved for the highest beneficial use. Based on an extensive and detailed study of Water Supply and Alternative Cooling options available to the BEP II project, staff has determined the use of 3300 acre-feet per year of Colorado River groundwater to be unnecessary. Staff recommends the project be amended to use dry cooling to eliminate significant impacts and conform to applicable LORS.

INTRODUCTION

In this section staff analyzes the potential effects of the BEP II project on soil and water resources. The analysis specifically focuses on the potential for the project to cause impacts in the following areas:

- Whether construction or operation would lead to accelerated wind or water erosion and sedimentation.
- Whether the project would exacerbate flood conditions in the vicinity of the project.
- Whether the project's demand for water would adversely affect surface or groundwater supplies.
- Whether project construction or operation would lead to degradation of surface or groundwater quality.

A determination of the conformance of the project with all applicable laws, ordinances, regulations and standards will be made.

Where actual or potential impacts are identified, staff has recommended either elimination of the impact or mitigation measures to reduce the significance of the impact and, as appropriate, has recommended conditions of certification.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

Clean Water Act (CWA)

The Clean Water Act (33 U.S.C. Section 1251 et seq.) was enacted with the intent of restoring and maintaining the chemical, physical, and biological integrity of the waters of the United States. The CWA requires states to set standards to protect, maintain, and restore water quality through the regulation of point source and certain non-point source discharges to surface water. Those discharges are regulated by the National Pollutant Discharge Elimination System (NPDES). In California, NPDES permitting authority is delegated to, and administered by the nine Regional Water Quality Control Boards (RWQCB).

Section 401 of the Clean Water Act requires that any activity that may result in a discharge into a water body must be certified by the RWQCB. This would apply to stream crossings during pipeline construction. This certification ensures that the proposed activity will not violate state and federal water quality standards.

Section 404 of the Clean Water Act authorizes the U.S. Army Corps of Engineers (ACOE) to regulate the discharge of dredged or fill material within the waters of the U.S. and adjacent wetlands. The ACOE issues individual site-specific or general (nationwide) permits for such discharges.

Reclamation Reform Act

Public Law 97-293 (43 U.S.C. section 390aa et seq.) Title II, Reclamation Reform Act of 1982 (following on the establishment of Reclamation Services by the Reclamation Act of 1902) allows for the management, development, and protection of water and related resources by the Bureau of Reclamation.

Colorado River – "Law of the River"

The Colorado River is managed and operated under numerous compacts, federal laws, court decisions and decrees, contracts, and regulatory guidelines collectively known as the "Law of the River." This collection of documents apportions the water and regulates the use and management of the Colorado River among the seven basin states and Mexico. The principal documents comprising the Law of the River are summarized below:

- **The Colorado River Compact, 1922**. The cornerstone of the "Law of the River", this Compact was negotiated by the seven Colorado River Basin states and the federal government in 1922. It defined the relationship between the upper basin states, where most of the river's water supply originates, and the lower basin states, where most of the water demands were developing. At the time, the upper basin states were concerned that plans for Hoover Dam and other water development projects in the lower basin would, under the Western water law doctrine of prior appropriation, deprive them of their ability to use the river's flows in the future. The basin was divided into an upper and lower half, with each basin having the right to develop and use 7.5 million acre-feet (MAF) of river water annually.

- **The Boulder Canyon Project Act, 1928.** This act: (1) ratified the 1922 Compact; (2) authorized the construction of Hoover Dam and related irrigation facilities in the lower Basin; (3) apportioned the lower basin's 7.5 maf among the states of Arizona (2.8 maf), California (4.4 maf) and Nevada (0.3 maf); and (4) authorized and directed the Secretary of the Interior to function as the sole contracting authority for Colorado River water use in the lower basin.
- **The Seven Party Agreement, 1931.** This agreement helped settle the long-standing conflict between California agricultural and municipal interests over Colorado River water priorities. The seven principal claimants - Palo Verde Irrigation District, Yuma Project, Imperial Irrigation District, Coachella Valley Irrigation District, Metropolitan Water District, and the City and County of San Diego - reached consensus in the amounts of water to be allocated on an annual basis to each entity. Although the agreement did not resolve all priority issues, these regulations were also incorporated in the major California water delivery contracts.
- **Treaty with Mexico, 1944.** Committed 1.5 maf of the river's annual flow to Mexico.
- **Upper Colorado River Basin Compact of 1948.** Created the Upper Colorado River Commission and apportioned the Upper Basin's 7.5 maf among Colorado (51.75 percent), New Mexico (11.25 percent), Utah (23 percent), and Wyoming (14 percent); the portion of Arizona that lies within the Upper Colorado Basin was also apportioned 50,000 acre-feet annually.
- **Colorado River Storage Project of 1956**. Provided a comprehensive Upper Basin-wide water resource development plan and authorized the construction of Glen Canyon, Flaming Gorge, Navajo and Curecanti dams for river regulation and power production, as well as several projects for irrigation and other uses.
- **The Arizona v. California U.S. Supreme Court Decision of 1964.** In 1963, the Supreme Court issued a decision settling a 25-year-old dispute between Arizona and California. The dispute stemmed from Arizona's desire to build the Central Arizona Project so it could use its full Colorado River apportionment. California objected and argued that Arizona's use of water from the Gila River, a Colorado River tributary, constituted use of its Colorado River apportionment, and that it had developed a historical use of some of Arizona's apportionment, which, under the doctrine of prior appropriation, precluded Arizona from developing the project.
- **The Colorado River Basin Project Act of 1968**. This Act authorized construction of a number of water development projects in both the upper and lower basins, including the Central Arizona Project (CAP). It also made the priority of the CAP water supply subordinate to California's apportionment in times of shortage, and directed the Secretary to prepare, in consultation with the Colorado River Basin states, long-range operating criteria for the Colorado River reservoir system.

STATE

California Constitution, Article X, Section 2

This section requires that the water resources of the State be put to beneficial use to the fullest extent possible and states that the waste, unreasonable use, or unreasonable method of use of water is prohibited. The conservation of such waters is to be exercised with a view to the reasonable and beneficial use in the interest of the people and for the public welfare. This section is self-executing.

Porter-Cologne Water Quality Control Act

The Porter-Cologne Water Quality Control Act of 1967, Water Code Section 13000 et seq., requires the State Water Resources Control Board (SWRCB) and the nine RWQCBs to adopt water quality criteria to protect state waters. These criteria include the identification of beneficial uses, narrative and numerical water quality standards and implementation procedures. The criteria that apply to BEP II are contained in the Colorado River Regional Water Quality Control Plan. These standards are typically applied to the proposed project through the Waste Discharge Requirements (WDRs) permit. The Porter-Cologne Water Quality Control Act also requires the SWRCB and nine RWQCBs to ensure the protection of water quality through the regulation of waste discharges to land under Title 23, California Code of Regulations, Chapter 15, Division 3, with discharges to surface impoundments covered under Title 27, Division 2.

California Water Code

Water Code Section 100. Requires the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and the waste or unreasonable use or unreasonable method of use of water be prevented, and that the conservation of such water is to be exercised with a view to the reasonable and beneficial use thereof in the interest of the people and for the public welfare. Provides for consistency of the Water Code with the requirements of Article X, Section 2 of the California Constitution.

Water Code Section 100.5. Declares to be the established policy of the State that conformity of a use, method of use, or method of diversion of water with local custom shall not be solely determinative of its reasonableness, but shall be considered as one factor to be weighed in the determination of the reasonableness of the use, method of use, or method of diversion of water, within the meaning of Article X, Section 2 of the California Constitution.

Water Code Section 13146. Requires that state offices, departments and boards in carrying out activities which affect water quality, shall comply with state policy for water quality control unless otherwise directed or authorized by statute, in which case they shall indicate to the State Water Resources Control Board in writing their authority for not complying with such policy.

Water Code Section 13247. Requires that state offices, departments, and boards, in carrying out activities which may affect water quality, shall comply with water quality control plans (i.e., Basin Plans) approved or adopted by the State Water Resources

Control Board unless otherwise directed or authorized by statute, in which case they shall indicate to the appropriate Regional Water Quality Control Boards in writing their authority for not complying with such plans.

Water Code Section 13552.6. Specifically identifies the use of potable domestic water for cooling towers, if suitable reclaimed water is available, as a waste or unreasonable use of water. The availability of reclaimed water is determined based on criteria listed in Section 13550 by the SWRCB. Those criteria include provisions that the quality and quantity of the reclaimed water are suitable for the use, the cost is reasonable, the use is not detrimental to public health, and the use will not impact downstream users or biological resources.

Water Code Section 13552.8. States that any public agency may require the use of reclaimed water in cooling towers if reclaimed water is available, meets the requirements set forth in Section 13550, that there will be no adverse impacts to any existing water right, and that if public exposure to cooling tower mist is possible, appropriate mitigation or control is provided.

State Water Resources Control Board (SWRCB) Policies

Resolution 75-58. The SWRCB has adopted policies that provide guidelines for water quality protection. The principal policy of the SWRCB that specifically addresses the siting of energy facilities is the Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling (adopted by the Board on June 19, 1975 as Resolution 75-58). This policy states that use of fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. This SWRCB policy requires that power plant cooling water should come from, in order of priority: wastewater being discharged to the ocean, ocean water, brackish water from natural sources or irrigation return flow, inland waste waters of low total dissolved solids, and other inland waters. This policy also includes cooling water discharge prohibitions such as land application.

Resolution 88-63. States that the Regional Water Quality Control Boards (Regional Boards) shall assure that the beneficial uses of Municipal and Domestic Supply (MUN) are designated for protection wherever those uses are presently being attained, and assure that any changes in beneficial use designations for waters of the State are consistent with all applicable regulations adopted by the Environmental Protection Agency. The MUN beneficial use refers to water that is suitable for community, military, or individual water supply systems including, but not limited to, drinking water supply. Where a body of water is not currently designated as MUN but, in the opinion of a Regional Board, is presently or potentially suitable for MUN, the Regional Board shall include MUN in the beneficial use designation. All surface and ground waters of the State are considered to be suitable, or potentially suitable, for municipal or domestic water supply and should be so designated by the Regional Boards with the exception of certain defined surface and groundwaters suitable for exception as a source of drinking water.

Such waters include surface and groundwaters with high TDS (greater than 3000 ppm TDS), untreatable contamination, greatly inadequate capability to supply adequate volume, and municipal or industrial wastewaters, process waters, mining wastewaters, or storm water runoff, provided that the discharge from such systems is monitored to assure compliance with all relevant water quality objectives as required by the Regional Boards. Also exempt are water in systems designed or modified for the primary purpose of conveying or holding agricultural drainage waters, aquifers regulated as a geothermal energy producing source or that have been exempted administratively pursuant to 40 Code of Federal Regulations, Section 146.4 for the purpose of underground injection of fluids associated with the production of hydrocarbon or geothermal energy, provided that these fluids do not constitute a hazardous waste under 40 CFR, Section 261.3

SWRCB Resolution 77-1. State Water Resources Control Board Resolution 77-1 encourages and promotes reclaimed water use for non-potable purposes.

SWRCB Resolution 68-16. This resolution (the "Anti-Degradation Policy") declares that it is the State's policy for maintaining existing high quality waters to the maximum extent possible. The existing high water quality must be maintained until demonstrated to the State that any proposed change will be consistent with the maximum benefit to the people of the state and will not unreasonably affect present or future beneficial uses. Any activity which discharges a waste to existing high quality waters will be required to provide the best practicable treatment necessary to assure that pollution or nuisance will not occur and that the highest water quality, consistent with maximum benefit to the people of the State, will be maintained.

SWRCB Water Quality Order 92-08

The SWRCB - Water Quality Order Number 92-08 requires the SWRCB to regulate industrial stormwater discharge from construction projects affecting areas greater than 1 acre to protect state waters. Under Order 92-08 the Colorado River Basin RWQCB will issue an NPDES permits for construction activities based upon an acceptable Storm Water Pollution Prevention Plan (SWPPP) submitted by BEP II.

Recycling Act of 1991

The California legislature's Water Recycling Act of 1991 (Water Code § 13575 et seq.). This Act is based on findings that the development of traditional water resources in California has not kept pace with the State's population, which is growing at the rate of over 700,000 per year and is anticipated to reach 36 million by the year 2010. Reclaimed water has many environmental benefits that include a reduced demand for water in the Sacramento-San Joaquin Delta, reduced discharge of waste into the ocean, and the enhancement of groundwater basins, recreation, fisheries, and wetlands. The use of reclaimed water has proven to be a safe, cost-effective, and reliable method of helping to meet California's water supply needs. It states that retail water suppliers, reclaimed water producers, and wholesalers should promote the substitution of reclaimed water for potable and imported water in order to maximize the appropriate cost-effective use of reclaimed water in California.

LOCAL

The City of Blythe and County of Riverside adhere to Federal and State water law, and have jurisdiction to issue grading permits with erosion and sediment control measures, and sanitation permits for installation of septic tanks and leach fields. The project will comply with all local requirements.

Riverside County

Riverside County, through the Riverside County General Plan - Water Quality Objective Number 1, maintains jurisdiction over nonpoint sources of water pollution including runoff from developed or urban areas, grading, construction, and agricultural activities.

Riverside County has also adopted ordinances, goals, and objectives through the Riverside County General Plan related to development in productive agricultural areas. Agricultural objectives are intended to encourage agriculturally productive lands to remain in agriculture and to discourage incompatible urban development adjacent to agricultural lands. Grading Ordinance 457 regulates grading and trenching to minimize soil erosion and ensure soil conservation. Environmental Hazards and Resources goals encourage the preservation and growth of agriculture while allowing agricultural land to phase into other land uses.

City of Blythe

The City of Blythe has adopted a number of policies and goals related to water resources in the City's General Plan. Water resources goals and policies are intended to promote wise utilization of the Palo Verde Valley's domestic, agricultural, and potable water sources and to encourage water conserving designs and technology to protect the Valley's vital water resources. The City has also adopted water resources policies intended to protect the quality of the Valley's water resources from potential sources of contamination, as well as requiring mitigation for significant impacts to water quality and quantity.

The City requires developments on the Mesa to submit an erosion control plan for review and approval by City officials. The City also reviews and approves project drainage plans.

ENVIRONMENTAL SETTING

REGIONAL AND VICINITY DESCRIPTION

The proposed project is located in Palo Verde, which is part of the greater Colorado River Valley. Palo Verde can be subdivided into two sections, the current flood plain, usually referred to as the Palo Verde Valley (Valley), and the upland terraces that flank the Valley, called Palo Verde Mesa (Mesa). The proposed project is located on the Palo Verde Mesa, one mile west of the Valley.

The Palo Verde Mesa covers approximately 280 square miles. The Mesa is bounded on the north by portions of both the Little and Big Maria Mountains, on the west by the McCoy and Mule Mountains, and on the south by the Palo Verde Mountains. The Palo Verde Valley forms the eastern boundary of the Mesa. Palo Verde, located within the Sonoran Desert, has an arid climate, characterized by mild winters and hot summers. The average temperatures range from a low of 41\F in January and December to a high of 108\F in July. The average annual rainfall, measured at the Blythe Airport, is only 3.7 inches.

Precipitation is typically concentrated about equally in two periods, one in the summer and one in the winter. Summer storms cause high intensity, short-duration rainfall with rapid runoff. Winter storms bring gentle rains with little or no runoff. Precipitation in the region falls far short of the water requirement for typical (non-desert) crops and landscaping vegetation. Palo Verde's climate, characterized by high temperatures, low humidity and frequent winds, places the region in the highest evapotranspiration zone in California (ETo zone 18). Specifically, ETo for Zone 18 is 71.6 inches. (ETo represents the average annual water requirement for grass, which is the reference crop for the ETo system.) (DWR, 1999)

Surface Hydrology

Surface hydrology in Palo Verde is predominated by the Colorado River, which is the only significant body of water in the region. The river flows on the east side of the Valley, about 9 miles to the east of the proposed project site. The average annual flows of the Colorado River, measured at the Palo Verde Dam, are 7,594,000 acre-feet per year (Metzger, 1973). Numerous dry washes cross the upland areas and provide infrequent and short-duration flows during intense rainstorms, flowing generally southeast across the Mesa to the Valley. However, the contribution to surface water flows from the dry washes in the Palo Verde area is negligible compared to the flow of the river. The USGS estimated runoff to the Valley from the McCoy Wash, the only large wash on the Palo Verde Mesa, averages only 800 acre-feet per year (Metzger, 1973).

There are numerous irrigation canals and drains in the region, located in the Palo Verde Valley. Drain flows are primarily derived from groundwater drainage and operational spills. These return flows are discharged to the Colorado River and are included in the PVID's computation of total Colorado River water use.

Groundwater

Structure and Hydrogeologic Units of the Groundwater System

The Colorado River, in conjunction with regional tectonic movements, is the agent that shaped the valleys and eroded, carried, and deposited the sediments to form the groundwater aquifers of the Colorado River Valley.

The Colorado River, over time, carved a string of alluvial valleys through the bedrock mountains of southeast California, which includes Palo Verde. These bedrock mountains roughly parallel the river throughout the Colorado River Valley system. The bedrock underlie and surround the valleys, defining the width, length and depth of each valley basin. This bedrock structure, which is relatively impermeable, forms the base of the Palo Verde basin sediments.

The sediments that fill the valleys of the Colorado River are collectively termed the river aquifer by the U.S. Geological Survey (USGS) (Wilson, 1994). Within the Palo Verde region, the USGS identifies four major hydrogeologic units, the fanglomerate, the Bouse Formation, the Older Alluvium and the Younger Alluvium.

The basal sedimentary unit in the Palo Verde region is the fanglomerate. This oldest unit is composed of poorly-sorted, cemented sandy gravel that were eroded from the surrounding mountains by the Colorado River. The fanglomerate blankets the irregular surface of the underlying bedrock with thickness that range from zero to over 4000 feet (Wilson, 1994). Owing to its composition, the fanglomerate produces relatively low water yields and is not usually tapped by the regional wells.

The Bouse Formation overlies the fanglomerate and represents a change in the depositional environment. The Bouse Formation was deposited during a tectonic shift in which the Colorado River Valley became an embayment of the Gulf of California. The embayment resulted in the deposition of a marine unit composed of limestone, clay, silt, sand and volcanic deposits and contains brackish water. Well logs indicate that the Bouse Formation is approximately 500 feet thick and is present throughout the Palo Verde region. Although sands and gravels in the upper portion of the Bouse Formation can produce water up to 15 gallons per minute (gpm) per foot of drawdown, yields are far less than the overlying river alluviums. Given its low yield and brackish water content, the Bouse Formation is typically treated as the base of the fresh-water aquifer system in the Palo Verde region.

The youngest major units in the region, the Older Alluvium and Younger Alluvium, were deposited by the Colorado River and are the primary water-bearing units of the groundwater aquifer system. The Older Alluvium is composed of sand, silt, and clay with minor amounts of gravel. The Younger Alluvium is predominately sand and gravel with minor amounts of silt and clay.

The Older and Younger Alluvium were deposited as a series of flood plain deposits. The Older Alluvium is composed of ancestral flood-plain deposits and results from all but the most recent cycle of erosion and deposition by the Colorado River. The Older Alluvium comprises all of the aquifer system deposits of the Palo Verde Mesa and extends beneath the Palo Verde Valley, underlying the Younger Alluvium. The most-recent erosional episode carved the lowest terrace of the present-day Palo Verde Mesa, as well as a trench in the central portion of these older flood-plain deposits. The Younger Alluvium fills this trench with about 100 feet of sediments and comprises the present-day flood plain deposits of the Palo Verde Valley. The Older Alluvium is much thicker than the Younger Alluvium, reaching thickness of 600 feet beneath the central portion of the Valley and the Mesa and pinching out along the bordering bedrock mountains.

The alluvial sediments of the Palo Verde aquifer system, beneath both the Palo Verde Valley and the Mesa, were deposited by the same processes. Lateral and vertical variations in permeability do occur, but all of the sediments are hydraulically connected to each other and to the Colorado River. No barriers to lateral flow have been identified within the alluvial sediments.

Groundwater Recharge

The Colorado River is the source of virtually all recharge to the Palo Verde aquifer system. The Colorado River accounts for both the water stored within the aquifers, as well as the ongoing recharge that replenishes the groundwater system.

Isotopic investigations by the USGS indicate that most of the water in the river aquifer of the Colorado River Valley originated from the river (Wilson 1994). These investigations specifically included analyses of groundwater from wells in Palo Verde. The Colorado River filled the valley sediments through lateral underground flow from the river channel and from vertical percolation to the groundwater system during periodic overbank flooding, prior to the building of dams.

Following the construction of the dams and the advent of agriculture, the Colorado River has continued to be the only significant source of recharge to the aquifers. Vertical recharge in the Valley from agricultural irrigation with water diverted from the Colorado River has replaced periodic overland flooding of the river. Water also continues to be transmitted laterally underground to recharge the aquifers of the Palo Verde Mesa.

The Palo Verde Irrigation District (PVID) annually irrigates approximately 90,000 acres of farmland, primarily on the Valley, with water diverted from the Colorado River (USBR web site, http://www.usbr.gov/dataweb/html/paloverde1.html#general). PVID has rights to divert river water for up to 104,500 acres on the Palo Verde Valley and up to 16,000 acres on the Palo Verde Mesa. To irrigate crops effectively, the amount of applied irrigation water typically exceeds the crop-water requirements by 10 to 25 percent. The portion of the applied water that is not consumed by crops percolates past the root zone to recharge the underlying aquifer. Groundwater recharge from irrigation in the Valley is more than sufficient to maintain a constantly high groundwater table throughout the Palo Verde Valley. In fact, the amount of groundwater recharge from irrigation has required the construction of a network of drainage ditches throughout the Valley to remove excess recharge that would otherwise cause groundwater levels to inundate the root zones of the crops. Irrigation from river diversions and the network of drainage ditches maintain constant groundwater water levels a few feet below land surface throughout the Palo Verde Valley.

Colorado River water also continues to be transmitted laterally to recharge the aquifers. Water is transmitted laterally between the river channel and the aquifer underlying the Palo Verde Valley and the Palo Verde Mesa. Because the aquifer beneath the Palo Verde Mesa and the Palo Verde Valley is hydraulically connected to the Colorado River, water can move between the river and the aquifer in response to withdrawal of water from the aquifer or differences in water-level elevations between the river and the aquifer. Changes in levels in the river or the groundwater level of the Valley or the Mesa will cause water to flow in the direction of the decline. By this means, water that originates from the river is transmitted through the aquifer system to replace groundwater pumped from wells throughout the Palo Verde region.

PVID water deliveries to the Mesa also contribute a minor amount of recharge directly to the Mesa. PVID currently delivers Colorado River surface water to 520 acres of farmland (BEP I 1999), which would contribute about 400 acre-feet/year of groundwater recharge, based on 4.3 foot evapotranspiration and an 85 percent irrigation efficiency.

The Palo Verde aquifer system probably receives a minor amount of recharge through groundwater underflow from the Chuckwalla Valley, which is located to the west of the Palo Verde Mesa between the McCoy Mountains and the Mule Mountains. USGS well logs and gravity studies indicate that the aquifers extend from the Palo Verde Mesa into the Chuckwalla Valley through a shallow, sediment-filled trench that is 2 to 3 mile-wide at the narrowest point. Groundwater recharge from the river extends from the Palo Verde area into the Chuckwalla Valley and commingles with local groundwater recharge within the Chuckwalla Valley (Wilson 1994). Local groundwater recharge would occur in the Chuckwalla Valley from rainfall percolation during infrequent large storm events. The USGS estimated that an average annual underflow of 400 acre-feet is transmitted from the Chuckwalla Valley into the Palo Verde Mesa area, based on measured groundwater levels (Metzger 1973).

The Palo Verde Mesa area may also receive a small amount of recharge through streambed seepage from the McCoy Wash, although this potential source has not been investigated or quantified. The McCoy Wash is dry, except during intense but infrequent, short-duration summer storms.

Groundwater recharge from precipitation is negligible. The evapotranspiration, with an average rate of 71.6 inches per year, far exceeds the rainfall, with a rate of only 3.7 inches per year. Employing the Eakin method, the USGS estimates that rainfall must exceed 8 inches per year to contribute directly to groundwater recharge.

Groundwater Elevations and Direction of Groundwater Flow

Evaluation of measured groundwater levels in the Palo Verde Mesa indicate that groundwater levels are sensitive to pumping and have responded to changes in groundwater use in the Mesa over the last 40 years. USGS estimated that static groundwater elevations near the project site were about 250 feet, mean sea level (MSL), in 1964 (Metzger 1973). However, groundwater development for agricultural irrigation on the Palo Verde Mesa increased significantly during the 1970’s and 1980’s, causing a regional decline in groundwater levels in the Mesa. USGS groundwater measurement records indicate that static groundwater levels declined more than 10 feet in the mid-1980’s in the vicinity of the BEP II (USGS National Water Information System-NWIS) Web Data for the Nation, http://nwis.waterdata.usgs.gov/nwis). Although most farming on the Mesa was discontinued by the early 1990’s, groundwater levels have not fully recovered.

Groundwater contours for Palo Verde, compiled by the USGS and based on 1964 water level measurements, indicates a regional pattern groundwater flow to the southwest (Metzger 1973). Groundwater contours for the Mesa roughly parallel the elevations and flow direction of the aquifer beneath the Valley and the Colorado River. Within the region, contours indicate that elevated groundwater levels beneath the Valley also causes localized flow from the western side of the Valley towards the Mesa. Increases in groundwater pumping in the Mesa since 1964 that have lowered Mesa groundwater levels would also have induced more westward flow from the Valley to the Mesa. Finally, in contrast, irrigation water deliveries by the PVID to the Mesa would cause localized groundwater recharge in the Mesa, would elevate groundwater levels on the Mesa, and could create areas of localized groundwater flow from the Mesa to the Valley.

WATER RESOURCES AND INFRASTRUCTURE

The primary water resources in the Palo Verde area are derived from the Colorado River through surface diversions and groundwater pumping. Surface diversions are used primarily to supply water to agriculture in the Valley. Groundwater pumping is used for local water supply by City of Blythe, by the Mesa Verde community, and by individual property owners, particularly in the Mesa, where the surface-water delivery infrastructure is limited. Downstream of the Palo Verde area, Colorado River water is completely allocated to numerous water rights holders including the Imperial Irrigation District, the Metropolitan Water District, the City and County of San Diego, and Mexico.

The Palo Verde Irrigation District (PVID) contains 131,228 acres along the Colorado River in southeastern Riverside and northeastern Imperial counties. The PVID diverts water from Colorado River for irrigation through a series of diversion canals originating at the Palo Verde Diversion Dam and returns water to the Colorado River through PVID drains. The PVID's diversion system includes approximately 244 miles of main and lateral irrigation canals and approximately 141 miles of open drainage canals carrying groundwater drainage and canal operational spill flows (PVID 2002). This network of irrigation and drainage canals throughout the Palo Verde Valley carries Colorado River Water to and from agricultural users and is essentially an extension of the Colorado River system.

The PVID has a Priority 1 water right to irrigate 104,500 acres of land in the Palo Verde Valley, and Priority 3 (16,000 acres) and Priority 6 (16,000 acres) water rights to irrigate lands on the Palo Verde Mesa. PVID's use of Colorado River water is calculated using a diversion-less-return methodology. During the 10-year period including 1987 to 1999 (excluding 1992 through 1994), the PVID's average annual diversion was approximately 913,000 acre-feet and the average annual return was approximately 513,000 acre-feet, resulting in a net average annual use of approximately 400,000 acre-feet. Given the total flows diverted and returned, the PVID's annual diversions and return flows from the Colorado River represent approximately 11.5 percent and 5.1 percent, respectively, of the river's annual flow volume (PVID 2002).

Citrus and forage crops are cultivated in the Palo Verde Valley and, to a lesser extent, on the Mesa. In the Valley, approximately 91,000 acres of the 104,500 acres with Priority 1 water rights are in agricultural production (PVID 2002). On the Mesa, approximately 4,000 acres are used for active agriculture (PVID 2002). Due to the costs associated with pumping groundwater for irrigation water, most agricultural activities on the Mesa have ceased because of decreased profitability. (PVID 2002). PVID currently delivers Priority 3 Colorado River water to about 520 acres for agricultural irrigation, which adds up to only 753 irrigated acres on the Mesa.

The PVID also plans to provide Colorado River water to the Metropolitan Water District of Southern California (MWD). MWD delivers water to 26 city, county, and municipal water agencies that serve more than 17 million people in Los Angeles, Orange, San Diego, San Bernardino and Ventura counties. Water sources for MWD include the Colorado River and State Water Project. On the Colorado River, MWD has Priority 4 and Priority 5 water rights totaling 1.1 million acre-feet. To supplement its allocation of Colorado River water, MWD is working with the PVID to implement a water conservation program within the PVID that will enable the PVID to provide MWD up to an additional 111,000 acre-feet of Colorado River water per year.

The proposed water conservation program involves rotationally fallowing farmland through voluntary agreements with an estimated 60 to 70 land contracts (PVID 2002). Water saved by the proposed water conservation program would be made available to MWD for its use within its service area. The proposed water conservation program includes limits on the amount of land fallowed within the PVID and within any individual participant's agricultural fields, land management measures, monitoring and verification measures, reporting, and payments to assist in stabilizing the farm economy within the Palo Verde Valley. The proposed water conservation program includes comprehensive measures to ensure that the program results in real and documented reductions in PVID water use such that water saved within the PVID can be transferred to MWD.

SOILS

Soils in the region are primarily derived from alluvial and colluvial deposits and range from coarse to moderately fine in texture. On the Palo Verde Mesa, soils tend to be well to excessively drained, coarse grained, sands, gravels and loam with relatively low erosion hazards (BEP II 2002, Section 7.14). In the Palo Verde Valley, soils tend to be finer in texture and are generally well drained fine-grained sands, silts, clays, and loam with relatively low erosion hazards.

Native vegetation in the region consists mainly of the Creosote desert scrub plant community characteristic of the Sonoran Desert. The vegetation in the area is dominated by three plant community types: creosote bush scrub associated with undeveloped desert areas; riparian plant communities associated with the channel banks of the Colorado River and its various canals and drains; and agricultural areas in active cultivation.

VICINITY AND SITE DESCRIPTION

Surface Hydrology

There are numerous irrigation canals and drains located in the Palo Verde Valley, near the site. The drain located closest to the proposed site is the Rannells Drain, approximately 1 mile to the east of the site at the foot of the Mesa. Flows in the Rannells Drain are primarily derived from groundwater drainage and operational spill from the upstream irrigation canal (PVID 2002). These return flows are discharged to the Colorado River and are included in the PVID's computation of total Colorado River water use.

The existing topography at the BEP I site is relatively flat with gradient towards the southeast. Drainage at the BEP I site has been modified to accommodate the BEP II facilities. The drainage plans for the BEP II facilities are intended to prevent the flow of runoff onto the project site from upgradient land. Runoff from upgradient of the project site is captured in a drainage channel along Buck Boulevard and routed to the retention basin at the southeast corner of the site. Runoff generated on-site will also be routed to the retention basin. The retention basin is intended to capture and percolate all runoff generated by a 100-year event and to prevent potential storm water drainage impacts (BEP II 2002, Section 7.13).

Runoff caused by major rainfall events will convey eroded soil to the BEP I retention basin, where the eroded soil would be trapped. When construction at the BEP I site is complete, the BEP I SWPPP indicates that areas of bare soil will be revegetated to limit the potential for soil erosion.

Groundwater

Hydrogeologic and water level conditions in the vicinity of the project site are typical for the Palo Verde Mesa.

Hydrogeology

The USGS has investigated the aquifer conditions in the Palo Verde region and provides general information on conditions in the vicinity of the project site. The project site is underlain by the Older Alluvium of the Colorado River, the Bouse Formation, and the fanglomerate. Based on a geologic cross section developed by the USGS (USGS 1973 plate 3) the Older Alluvium, which is the primary aquifer for the Mesa, is over 500 feet thick in the vicinity of the project site. It is assumed that the Bouse Formation and the fanglomerate, which tend to be significantly less permeable than the Older Alluvium, are non-productive zones beneath the effective aquifer zones.

The Older Alluvium is composed primarily of sand, silt, and clay with minor amounts of gravel. The Older Alluvium includes a narrow zone of gravel lenses, which occur within a mile from the Mesa-Valley boundary (USGS 1973). Most wells on the Mesa draw water from the sand layers of the Older Alluvium; the wells completed within the zones of gravel lenses are highly productive.

Aquifer Parameters

Aquifer parameters include confining conditions, hydraulic conductivity and storage, which are intrinsic characteristics of the aquifer materials. Although the USGS (1973) and DWR (1978) have generally described the water-bearing properties of the Mesa, no specific information on the localized aquifer parameters of the project site was included in these earlier studies. However, the recent aquifer test performed on the BEP I wells have provided data from which aquifer parameters for the local conditions can be calculated. The construction of wells and aquifer testing at BEP I has provided detailed information on the aquifer conditions adjacent to the proposed project site.

Well logs for the BEP I production wells PW-1 and PW-2 indicate that the local aquifer is more than 600 feet thick and consists of coarse-grained materials with minor amounts of silt and clay. Layers alternate between well-sorted beds, which would transmit most of the horizontal flow in the aquifer and poorly-sorted beds, which would tend to slow the vertical transmission of water. PW-1 also encountered at least two thick gravel and sand lenses. The BEP I project developer encountered no confining clay layers during well drilling and concluded that the aquifer is unconfined in the BEP I aquifer testing reports (BEP I 2002).

Based on aquifer tests for both production wells, BEP I has reported an average transmissivity (a measure of an aquifer's ability to transmit water through it) of about 75,000 feet^2/day and an average storativity (a measure of an aquifer's ability to store water within it) of 0.04 (BEP I 5/2003 and 6/2003). Soil and Water Resources Table 1. summarizes the aquifer parameters calculated and presented in the BEP I final aquifer test reports (BEP I, 5/2003, 6/2003).

Soil and Water Resources Table 1
Blythe Energy Project Calculated Aquifer Parameters

BEP I Production Well Name	Transmissivity (feet^2/day)	Storage (dimensionless)
BEP I PW-1	69581	0.04
BEP I PW-2	79718	0.04
Average	74650	0.04

Source: BEP I (5/2003, 6/2003)

Given the proximity of BEP I to the BEP II site, it is reasonable to assume that aquifer parameters are essentially the same at both sites.

Static Groundwater Levels

Static groundwater levels measured at the BEP I project site can also be used to estimate groundwater level conditions at the BEP II site. Prior to the onset of groundwater testing, the BEP I reported the depth to groundwater in the monitoring and tests wells ranged from 85.6 feet to 91.8 feet (BEP I 2002). Based on USGS well measuring-point surveys, groundwater level elevations would have been 249 feet MSL. However, static groundwater levels in the vicinity of the BEP project will decline when this project begins operation. BEP I has projected that the average long-term pumping rate would be approximately 2,040 gpm (3290 acre feet/year). Based on drawdown calculations reported by BEP I, static groundwater levels at the proposed BEP II well sites will decline about 4.6 feet, lowering static groundwater levels to less than 245 feet MSL at the BEP II site.

USGS Accounting Surface Assessment

Both the BEP II project and wells are located within the boundary of the USBR/USGS accounting surface that defines the area and groundwater elevations from which groundwater wells will yield water that will be replaced with Colorado River water (Soil and Water Resources Figure 1). The USGS accounting surface elevation is approximately 245 feet (MSL) at the proposed BEP II site (USGS 1994) (Soil and Water Resources Figure 2). As previously discussed, the static groundwater level at the BEP II site will be less than 245 feet (MSL) once operational pumping for BEP I stabilizes.

Therefore, according to the USGS accounting surface method, the water supply wells for BEP II will yield water that will be replaced with Colorado River water.

Sources of Recharge

There are no natural surface-water sources to provide steady or significant groundwater recharge on the Mesa. As discussed previously, there are no near-by streams or lakes and precipitation rates are too low to contribute to groundwater recharge. The meager precipitation that does occur on the Mesa is rapidly consumed by evaporation or vegetation. A minor amount of groundwater recharge may be contributed to the Mesa by underflow from the Chuckwalla Valley and by storm-event percolation from infrequent runoff flows in the McCoy Wash, as discussed previously. The Chuckwalla Valley is located 5 miles west of the project site. The McCoy Wash originates 18 miles to the northwest and terminates at the Mesa-Valley boundary about 3 miles north of the project site. The BEP II site is not located within the McCoy Wash watershed and is outside of the Wash's 100-year floodplain (BEP II 2002, Section 7.13).

In addition, irrigation deliveries to the Mesa by PVID currently do provide a small steady source of groundwater recharge. PVID currently delivers surface water for irrigation to 520 acres of farmland under a 1996 Priority-3 contract for Colorado River water for up to 16,000 acres on the Mesa, (BEP I 1999). Overall, the primary and nearest source of recharge to the Mesa and to BEP II is lateral groundwater underflow from the Palo Verde Valley, which borders the Mesa about one mile east of the project site. Irrigation water diverted from the Colorado River constantly recharges and maintains the high groundwater levels in the Palo Verde Valley. Based on the available information, staff has concluded that virtually all groundwater production on the Mesa, including the proposed BEP II wells, yields water that originated from and is replaced by Colorado River Water.

Existing Groundwater Use

The Applicant provided a brief description of historical and current water use on the Palo Verde Mesa (BEP II 2002, AFC, page 7.13-10). Historically, groundwater has been developed on the Mesa for agricultural, industrial and domestic use. Agricultural irrigation with groundwater increased from about 200 acres in the mid-1960's to over 6,500 acres in the 1970's and 1980's. However, groundwater irrigation for agriculture declined significantly in the 1990's. Current land use and water use on the Mesa could be described as sparse.

The Applicant has identified the location of several existing industrial, agricultural, and residential wells near the project site. Industrial groundwater users include the new Bythe Energy Project, the Blythe Airport and a few small businesses. The oldest well on the Mesa may be the well at the Blythe airport , which served as a military base during World War II. The largest industrial groundwater user in the vicinity of the project is the BEP I, with wells located about 1000 feet from the proposed BEP II well sites. The Applicant has also reported 3 agricultural wells located about 1 mile from the project. Other than the BEP I wells, the closest existing well to BEP II is the Thermal King shop well, located on Hobsonway, about 2,700 feet from the project well sites. In addition to agricultural and industrial wells, there are also several wells in the vicinity of the site that provide groundwater to domestic users. The largest of these wells serve the Mesa Verde community and are located 2 miles from the project site (BEP II, Data

Request responses, Figure 64-1). In addition, the Applicant reports 10 other domestic wells located between ½ to 2 miles from the proposed project well sites.

Water Quality

Groundwater Quality

Groundwater quality in the Palo Verde Mesa could be describe as fair to poor. The groundwater in the Palo Verde Mesa typically has higher TDS values than the Palo Verde Valley (BEP I 1999). The USGS reports that analyses of groundwater samples indicated that the best quality water on the Mesa is found within a mile or two of the Valley with a gradual increase in the mineral content of groundwater with increasing distance from the Valley.

Recent Groundwater Quality Testing

The native chemical composition of groundwater near the project site is best described as either a sodium-sulfate or sodium-chloride water. The Applicant (BEP II 2002a, Response to Data Request 65) and BEP I (2000a) report that groundwater analyses indicate concentrations of total dissolved solids, specific conductance, sulfate, chloride and fluoride are at or slightly above the Secondary Drinking Water Standards. Soil and Water Table 2 summarizes the results of groundwater sample from the BEP I production well conducted shortly after construction in 2001 (BEP II 2002). These groundwater analyses provide a profile of most physical and chemical characteristics of groundwater, but does not include analyses for manmade organic chemicals.

Soil and Water Resources Table 2
Primary Supply Water Quality

Constituents	Mean Concentration at BEP II Production Wells (PW-1 and PW-2) May – November, 2001
Cations (ppm)	(mg/l)
Calcium	41.5
Magnesium	8.5
Sodium	298
Iron Total	0.22
Potassium	4.2
Ammonia	<0.1
Barium	<0.1
Anions (mg/l)	
Sulfate	271
Chloride	280
Fluoride	1.8
Nitrite	3.3
Phosphate	<0.5
Bicarbonate	NA
Carbonate	NA
Hydrate	NA
Metals (mg/l)	
Aluminum	0.10
Arsenic	0.003
Boron	0.60
Cadmium	<0.001
Copper	0.07
Chromium	0.002
Lead	<0.005
Mercury	<0.005
Nickel	<0.01
Selenium	0.009
Strontium	0.93
Tin	<0.01
Zinc	0.07
Other	
Turbidity (NTU)	1.24
pH (SU)	7.4
Conductivity (umhos/cm)	1720

Source: BEP II, 2002, Section 7.13 and AFC Table 7.13-2
NTU - Nephelometric Turbidity Unit;
SU – Standard Units;
ND – none detected;
mg/l – milligrams/liter

BEP I's pre-certification groundwater testing detected low concentrations of manmade chemicals, which do not exceed drinking water standards. The chemicals that were detected include volatile organics, semi-volatile organics, pesticides and elevated concentrations of nitrate (BEP I 2000a). BEP I reported detecting the following concentrations of volatile organics and semi-volatile organics:

- Styrene (8.1 µg/L, method detection limit (MDL) of 0.5 µg/L)
- Ethylbenzene (0.5 µg/L, MDL of 0.5 µg/L)
- Toluene (2.7 µg/L, MDL of 0.5 µg/L)
- Total Xylenes (2.0 µg/L, MDL of 0.5 µg/L)
- Methylene Chloride (0.5 and 2.2 µg/L, MDL of 0.5 µg/L)
- 1,4 Dichlorobenzene (1.5 µg/L, MDL of 0.5 µg/L)
- Di (2 Ethyl Hexyl) Phthalate (3.4 µg/L, MDL of 3.0 µg/L)

The Applicant has also provided a summary of groundwater analyses from the BEP I production wells, sampled in August 2002, which are similar to the results of the 2001 sampling listed in Soil and Water Table 3. However, the summary is incomplete because it only included constituents that exceeded the primary or secondary drinking water standards and included no information on the analyses of manmade organic chemicals. Staff has requested a complete listing of soil and water quality sampling for volatile and semi-volatile organic compounds, pesticides, and nitrates (BEP II 2002a, Data Request 64). The Applicant has not provided this report to the CEC. Staff will need to evaluate the most recent sampling results to evaluate potential impacts related to current concentrations of these constituents in groundwater to complete the analysis of this issue for the FSA.

Contaminant Source Investigations

With the exception of elevated nitrate concentrations, which are likely caused by agricultural fertilizers and mobilized by irrigation, no source for these manmade chemicals has been identified by BEP I or by the Applicant. BEP I investigated the two potential point sources closest to the BEP II project site, an old mobile home site and the Blythe Airport Dump. The old mobile home site, no longer occupied, is located on the southeast corner of the BEP I site. The dumpsite is located on the northern portion of BEP II and extends north beyond the site boundary. The dump is associated with the former Blythe military airbase and consists of demolition debris and trash (BEP II 2002a II, response to Data Request 65) BEP I also identified elevated lead concentrations in 1 of 4 soil samples at the dumpsite. However, most of the organic chemicals found in the BEP I sampling program were detected in the well located near an old mobile home site, rather than in the well closest to the dumpsite.

The Applicant also performed a Phase I Environmental Site Assessment Process in conjunction with its AFC, as well as a more extensive search for potential sources of contamination within a 3-mile radius of the proposed project site. This assessment included a review of federal, State of California and local documents for sites using hazardous material or sites with historical or current contamination issues (BEP II 2002a, response to Data Request 65). Eighty three (83) potential sites for contamination within three miles of BEP II were identified by the initial search (some duplicate listing may be included). From the 83 initially identified sites, the Applicant identified 8 sites because these sites are located up-gradient from the BEP II site or could be affected by project pumping.

Of these 8 potential sites for contamination near BEP II, 6 sites reported that only soils were affected or that spills were remediated within 24 hours. The remaining 2 sites are the Blythe Airport Dump, which is listed in the State Landfill database, and the Blythe

Lemon Ranch No. 41 and No. 69, which are listed in the LUST, ERNS and CORTESE databases. The State Landfill database presumably lists all landfills in the state. However, other than the elevated lead concentrations in one soil sample from the Blythe Airport Dump, no leaks have been reported and no other chemicals in concentrations that constitute contamination have been reported at the dumpsite.

The LUST, ERNS and CORTESE data base reported gasoline leaks at the Blythe Lemon Ranch No. 41 and No. 69 in October, 1991. BEP I states that the spills occurred 0.25 miles (about 1,300 feet) "down gradient" of the proposed project site. The Colorado River Regional Water Quality Control Board signed off the leak at the Blythe Lemon Ranch No. 69, but no signoff date was reported for the Blythe Lemon Ranch No. 41 in the database. Staff may request more information regarding the exact location of the spills to determine the potential for chemical diffusion and potential for groundwater transport, as well as the status of the Blythe Lemon Ranch No. 41 spill.

Soils and Vegetation

The soils at the site (Soil and Water Resources Table 3) are primarily made up of four soil types with textures ranging from moderately fine to coarse (BEP II 2002, Table 7.14-1). The water erosion hazard is expected to be slight at the site, along the transmission lines, and at the interconnection to the SoCalGas natural gas pipeline. At the interconnection to the El Paso natural gas pipeline, the erosion hazard is expected to be nonexistent or slight, except for the segment extending from Rannells Drain to Hobsonway. The water erosion potential along this segment is considered to be slight to moderate (BEP I 1999). The wind erosion potential for most of these soils is moderate to high.

Soil and Water Resources Table 3

Soil Types Affected & Characteristics

Project Element	Soil Name	% Slope	Depth (inches)	USDA Texture	USCS Classification (1)	Erosion Factors	Permeability (in/hr)	Drainage	Erosion Hazard Rating
Site Area	Aco	<1	0-46	Sandy Loam	SM	Low	0.0-6.3	Well Drained	Slight
			46-60	Fine Sand	SM	Low	0.3-20.0	Well Drained	Slight
Site Area	Carrizo	<2	0-37	Gravelly Sand	SW-SM	Low	6.3-20.0	Excessively Drained	Slight
			37-60	Cobbly Sandy Loam, Sand	GP-GM	Low	6.3-20.0	Excessively Drained	Slight
Site Area	Orita	<1	0-10	Gravelly Loamy Sand	SM	Low	2.0-6.3	Well Drained	Slight
			10-22	Fine Sandy Loam	SM	Low	0.63-2.0	Well Drained	Slight
			22-68	Gravelly Clay Loam	CL	Low	0.2-0.63	Well Drained	Slight
			68-80	Gravelly Fine Sandy Loam	GM	Low	0.63-2.0	Well Drained	Slight
Site Area	Rositas	<2	0-72	Fine Sand	SP-SM	Low	6.3-20.0	Excessively Drained	Slight to Moderate

(BEP II 2002, Section 7.14 & Table 7.14-1)
(1) Unified Soil Classification System based on laboratory soil grain size analysis and visual classification. CL= clay, ML = silt, etc.

The Aco sandy loam is a well drained soil derived from mixed alluvium on the terraces slightly above the flood plain. The representative profile for Aco soils is approximately five feet deep. The Aco sandy loam has a moderately rapid permeability. Lands with Aco sandy loam are classified as prime agricultural land and has a high revegetation potential. Where the soil is bare, runoff is slow and erosion hazards are slight (BEP II 2002, Section 7.14).

The Carrizo gravelly sand is an excessively drained soil containing coarse fragments, predominantly gravel, and is found in arroyos. The representative profile for Carrizo soils is approximately five feet deep. The Carrizo gravelly sand has a rapid permeability. Lands with Carrizo gravelly sand are classified as non-prime agricultural land and has a low revegetation potential. Where the soil is bare, runoff is very slow, and there is a slight erosion hazard (BEP II 2002, Section 7.14).

The Orita gravelly fine sandy loam is a generally well-drained soil derived from alluvium deposited by the Colorado River. The soil profile is greater than five feet deep and the permeability is moderately slow. Lands with Orita soils are classified as prime agricultural land with a high revegetation potential. Where the soil is bare, there is moderate runoff and a slight erosion hazard (BEP II 2002, Section 7.14).

The Rositas fine sand is an excessively drained soil derived from alluvium deposited in the Palo Verde Valley and on the Palo Verde Mesa by the Colorado River and formed in sandy eolian material blown from recent alluvium. The soil has a representative profile greater than five feet deep and a rapid permeability. Lands with Rositas fine sand is classified as prime agricultural land and has a high revegetation potential. Where the soil is bare, runoff is very slow and erosion hazards are slight to moderate (BEP II 2002, Section 7.14).

The BEP II site is not known to have been utilized for agriculture and has not been previously irrigated. Prior to construction of the BEP I facility, the bush-scrub community occupied approximately 74 acres of the site, while the remaining 2 acres were in agricultural or industrial use (BEP I 1999). The BEP II project is an expansion of the BEP I site and occupies approximately 60 acres east of the BEP I site. When construction is complete, the BEP I SWPPP indicates that areas of bare soil will be revegetated to limit the potential for soil erosion. A draft SWPPP that includes the BEP II project has not been submitted for staff review at this time.

The BEP II site is on land that has been designated as Farmland of Local Importance in the Important Farmland Inventory prepared by the California Department of Conservation (BEP II 2002, Section 7.14). The land to the east of the BEP I site is used to grow lemons.

There are no significant surface water bodies in the vicinity of the site. Drainage on the Palo Verde Mesa in the vicinity of the site generally flows to the southeast toward the Palo Verde Valley and the Colorado River. The Colorado River is located about 9 miles to the east of the site.

PLANT WATER REQUIREMENTS

Heat & Water Balance

The AFC includes two main sources of technical information relevant to water consumption; the heat balances and the water balances.

Heat Balances

The heat balances are provided in Soil and Water Resources Table 3.

Soil and Water Resources Table 3
Comparing Heat Balances
From the AFC and Responses to Data Request 200

AFC Figure	Ambient Temperature º F	Relative Humidity %	Gas Turbine Inlet Cooling	Duct Burner Temp. Rise º F
Fig. 2.0-6A	95	40	Spray on	**-13.8****
Fig. 2.0-6B	95	40	Spray off	+11.1
Fig. 2.0-6C	59	60	Spray on	+10.3
Fig. 2.0-6D	59	60	Spray off	+12.6

** Auxiliary firing achieves a heat “rise” of NEGATIVE 13.8 \F, an impossibility (see below)

The heat balances are not consistent with current design selection, which uses mechanical chillers rather than evaporative coolers for GTIC (gas turbine inlet cooling) (BEP II 2003). The heat balances show direct evaporation of water for GTIC, i.e.; spray water injection.

Typically, the highest ambient temperature heat balance would represent the condition of maximum consumption of gas fuel and maximum consumption of water for cooling purposes. Maximum loading and consumption is achieved in a combined cycle plant when auxiliary burners are operated. Auxiliary burners, or duct burners, are natural gas fueled burners located in the duct work between the gas turbine exhaust and the corresponding entrance to the heat recovery steam generators (HRSG). These burners are fired in order to raise the temperature of the flue gas entering the HRSG’s, thereby increasing steam production from the HRSG’s.

This steam production in turn causes an increase in the output of the steam turbine but not for the gas turbines. Increasing the output of the steam turbine requires greater cooling for the exhaust from the steam turbine, which is low pressure steam condensed in the main condenser using cooled water from the main cooling tower. AFC Figure 2.0-6A shows a flue gas (gas turbine exhaust) temperature of 1106.3 ºF leaving the gas turbines, followed by a duct burner, and an output from the duct burner of 1092.5 ºF. So the temperature of the flue gas has actually decreased by going through the duct burner area. This is not only erroneous, but is, in fact, a physical impossibility.

Regardless of the cause of this anomalous data, it is certain that the indicated load for the power plant, and specifically for the heat load input to the condenser, has been understated by the Applicant. Therefore this heat balance can not represent a maximum load condition, a condition of maximum consumption of gas fuel, or a condition of maximum consumption of cooling water. Data Request 200 asked for “correct and legible heat flow diagrams.” The response provided legible diagrams, but the AFC Figure 2.0-6A diagram is apparently not correct; corrected diagrams may be requested prior to the FSA.

Water Balances

The labeling on AFC Figure 7.13-10A Water Balance Diagram for 59 degrees specifies that this is for relative humidity of 60% and “With Evaporative Cooling”. The latter is apparently in reference to the gas turbine inlet cooling (GTIC) method. The diagram shows a cooling tower for gas turbine inlet cooling, rather than a spray cooler as in the heat balance diagrams. This could be interpreted as the heat sink of a chiller system as currently selected for plant design, or as the evaporative system specified when the water balance was drawn in December 2001 (a date obtained from the drawing “block” or title area of the water balance). A change in water consumption has not been requested following the adoption of the mechanical chiller system, although response to Data Request 144 indicates that somewhat more cooling water would be required for the mechanical chiller.

The label on AFC Figure 7.13-10B Water Balance Diagram for 110 Degrees specifies 5 percent relative humidity, and “With Evaporative Cooling”. Similar to the above, the water balance appears to assume GTIC by evaporative cooling.

The water balances and related AFC text discussions do not specify the amount of auxiliary firing utilized in modeling for the numbers. The water balances seem to show evaporative cooling towers for gas turbine inlet cooling rather than the spray injection shown on the heat balances or the mechanical chilling system that is now the design basis. The Supplemental Information of July 14, 2003, page 7.13-1 states:

> “The replacement of the evaporative cooling system with the inlet air cooling system does not affect the amount of water to be used by the BEP II”.

That is, the selection of mechanical chilling will not cause the plant to exceed an average of 3300 AFY of water consumption, which is an annual amount needed for plant operation according to responses to Data Requests 144 and others.

In order to investigate and confirm the water balance numbers, staff prepared water balances using the heat balance information. Since the heat balances do not specify the main cooling system water consumption, derivation required analysis from the steam turbine exhaust conditions using engineering procedures and judgment typically used by staff for such investigations. The tables below compare the main items of water consumption.

Soil and Water Resources Table 4

Data for 59 º F Ambient Temperature

	Water Balance*		Heat Balance**	
	gpm	AFY	gpm	AFY
Main cooling tower evaporation only	1535	2476	1983	3199
GTIC cooling tower evaporation	20		20	
Evaporation pond inflow	14		18	
Other	11		10	
Total Water Required	1581	2550	2031	3276

* Auxiliary firing unknown. Power output unknown.

** Auxiliary firing (10.3 °F rise). Spray cooling of gas turbine inlet at 10 gpm/unit or 20 gpm total. Power output 522 MW gross

Soil and Water Resources Table 5
Data for 95 & 110 º F Ambient Temperature

	Water Balance*		Heat Balance**	
	gpm	AFY	gpm	AFY
Main cooling tower evaporation only	2604	4200	1854	2991
GTIC cooling tower evaporation	133		50	
Evaporation pond inflow	20		14.2	
Other	11		10	
Total Water Required	2768	4465	1928	3110

* Auxiliary firing unknown. Power output unknown.

** NEGATIVE auxiliary firing of 13.8 °F.
GTIC cooling with spray water at 25 gpm/unit or 50 gpm total.
Power output 487 MW gross.

As stated above, the Heat Balance numbers in the figures were derived by staff, whereas the water balance numbers were provided by the Applicant in the AFC or in responses to Staff Data Requests. It is difficult to explain the large deviation between the results. Auxiliary firing and subsequent plant load can account for some differences, but not all.

Lacking consistent water consumption results from the above, further review was made of all data submitted by the Applicant in the AFC and in the various Data Responses. The underlying assumptions are not always known, particularly regarding auxiliary firing.

Soil and Water Resources Table 6 summarizes the available information on water consumption from the AFC and Data Requests:

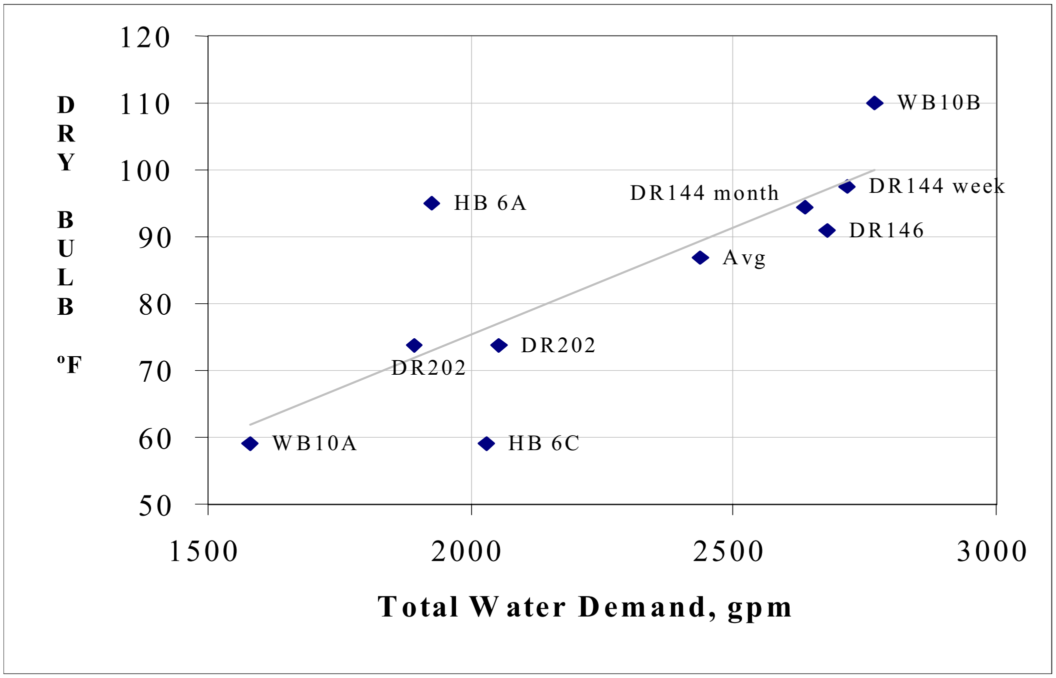
Soil and Water Resources Table 6
BEP II Daily Water Consumption

Operating Conditions					Water Flows			
Data ID	Temp ºF	RH %	GTIC	Aux Firing	Total, gpm	GTIC, gpm	Pond In, gpm	Total, AFY***
WB10B	110	5	Evap		2768	133	20	4465
DR144 weekly	97.4	25	Chiller	Base	2715	227	20	4380
DR144 month	94.5	25	Chiller	Base	2634	220	20	4251
HB -6A	95	40	Spray	-13.8 ºF	1928	50	14*	3110
DR146	91	30	Chiller		2678	223	20	4320
Avg	87	20	Chiller	Base	2438	200	15	3950
DR202	73.6**		Chiller		2052	160	20	3310
DR202	73.6		Evap		1892	**0.03**	20	3052
HB 6C	59	60	Spray	10.3 ºF	**2031**	20	18*	3276
WB10A	59	60	Evap		1581	20	14	2550

Key to the Data ID's
WB10B refers to the Water Balance, Figure 7.13-10B, of the AFC
DR144 weekly refers to the response to Data Request DR144, the weekly of the two tables.
DR144 month refers to the same, the monthly of the two tables.
HB-6A refers to the Heat Balance Figure 2.0-6A of the AFC. Total flow is derived by staff analysis of given information on the heat balance.
DR146 refers to the response to DR146.
Avg refers to Summer average temperature, staff calculation.
DR202 refers to response to DR202, tables for chiller and evaporative cooler for gas turbine inlet cooling.
HB6C refers to Heat Balance Figure 2.0-6C, similar to HB-6A above.
WB10A refers to Water Balance, Figure 7.13-10A, of the AFC.
GTIC is abbreviation for gas turbine inlet cooling. In the 4th column it indicates whether cooling is accomplished by evaporative cooler (abbreviated "evap"), mechanical chiller system (abbreviated "chill") or direct spray cooling at the turbine inlet (abbreviated "spray").
* Numbers derived by staff
****** Average annual temperature. Not provided in DR response, average is "median" from Blythe Airport, provided by WRCC.
******* AFY is acre-feet per year, but is an instantaneous rate rather than intended to indicate a year of operation.

The above are further viewed in the Soil and Water Figure 3 below, which is a graph of the total water flow to the plant versus ambient temperature in ºF from the Soil and Water Table 6 above. Examination of the available information indicates clearly that the heat balance numbers, those indicated in bold in Soil and Water Table 6 above and labeled HB-6A and HB-6C in the graphic below, disagree with other data. The bolded number in Soil and Water Table 6 indicated for the GTIC water flow in DR202 response also appears to be erroneous.

Soil and Water Figure 3
Comparative Water Flow Data



The Water Balance for 110 ºF, labeled WB10B above, also deviates from expected. However, on modifying to reflect the choice of chiller system for GTIC rather than evaporation, as submitted, the volume returns to an expected value nearer 2900 gpm.

Without knowing the specifics of how the operator intends to operate the plant with regard to the use of auxiliary firing of the duct burners, it is not possible to exactly determine the water consumption. Much of the information in the Heat Balances (AFC Figures 2.0-6A through D) does not appear to be in agreement with the operator's intended use of the plant. However, using the heat balance data for steam turbine exhaust only, making adjustments as needed, and with the addition of cooling towers for gas turbine inlet cooling, staff has calculated that for the average year the plant would consume approximately 3262 acre-feet (2022 gpm). This is in very close agreement with the Applicant's expressed average in DR202 Chiller table. The Applicant now intends to use mechanical refrigeration system (chiller) for TGIC, and states that this makes little difference in total water consumption. Therefore, the value of 3262 afy is sufficiently consistent with the Applicant's stated expectation of 3300 AFY.

Staff has taken it on face value that the Applicant will build a Siemens V84.3A, two on one combined cycle power plant, but notes that Siemens usually does not provide the V84.3A gas turbines in the US, but instead supplies the Westinghouse 501F.

After consideration of all factors and despite the inconsistency of the Applicant's data, staff believes it is appropriate to use the volumes given by the Applicant and repeated in Soil and Water Resources Table 7 for expected total water demand. The "Derived" values represent calculation by staff of the conditions given, and are in reasonable agreement with the Applicant's expectations.

Soil and Water Table 7
Estimated Total Water Demand
(Acre-feet)

	AFC/DR	Derived
"Average" annual consumption of water	3300	3262
Peak 4 month consumption (91 ºF average ambient)	4320	4130
59 ºF water consumption rate	2550	2500

Staff is, therefore, in agreement with the Applicant that the maximum annual amount of water reasonably required to operate the project using evaporative cooling is 3300 afy.

PROJECT WATER SUPPLY

BEP II proposes to obtain water for project operations from two water supply wells, constructed on site. Both the BEP II project and wells are located within the boundary of the PVID. Furthermore, the wells are located within the USBR/USGS accounting surface defining groundwater that will be replaced with Colorado River water.

The Applicant has reported that project operations will require a long-term average total water requirement of 3,300 acre-feet per year (2,045 gpm). Water produced by BEP II will be completely consumed and no water will be recharged to the aquifer. Under extreme demand and climate conditions, staff has calculated that water production could increase to 2,890 gpm for a period of 4 months, at a maximum.

The Applicant has proposed to interconnect the water delivery system of the BEP II with BEP I to provide operational flexibility. Each of the project wells on both sites are designed to independently meet the project water requirements. The second well on each site is designed to provide backup to the first well. In other words, only two of the four wells are needed at any one time to meet the requirements of BEP I and BEP II. Therefore, if the delivery systems of the two projects were connected, both wells on either site could provide the entire water supply to both sites while the wells at the other site could be idle. If this condition did occur, the center of drawdown would shift and alter the pattern of well interference by a maximum of 500 feet.

BEP I will also use groundwater for project operations. The water requirements for BEP I are very similar to BEP II's water requirements. BEP I has reported a long-term average total water requirement of 3,290 acre-feet per year (2,040 gpm). Under extreme demand and climate conditions, BEP I has reported that water production could increase to 2,558 gpm for a period of 4 months, at a maximum.

WASTEWATER DISCHARGE

The wastewater system is shown schematically on the water balance diagrams. More detailed flow diagrams are not available. The raw water from the on-site wells is directed to three places: a minor amount to in-plant utility uses, on the order of 5 percent is directed to the gas turbine inlet air cooling system, and the remainder to the steam turbine condenser cooling system (cooling tower). The two larger uses are for evaporation in cooling towers of 7 cycles of concentration. The blowdown/wastewater from the cooling towers is sent to a brine concentrator system. In this equipment approximately 95 percent of the water is flashed off in a vacuum system as pure water, the remaining 5 percent containing essentially all the dissolved solids is sent to an evaporation pond. The pure water is then directed to the makeup system for the plant steam process and though the demineralizer system as needed, with the rest of the pure water returned to the main cooling tower.

The wastewater sent to the evaporation ponds can accurately be described as brine, and is actually far "saltier" than ocean water (see also **Biologicial Resources**). This brine is left exposed to the sun and wind so that the water will evaporate, and in due course (years) all the water will be removed and only the chemical solids that were initially brought in with the well water and any non-volatile power plant water treatment chemicals, will remain. These solids will eventually be removed to a suitable solids disposal site. The wastewater has the following chemical characteristics:

Soil and Water Resources Table 8
Estimated Constituent Concentrations in
Brine Discharged to Evaporation Ponds

Constituents	Estimated Concentration (mg/l)
Dissolved Silica	4,236
Dissolved Iron	38.7
Calcium	7,263
Magnesium	1,488
Sodium	52,150
Potassium	735
Sulfate	47,425
Chloride	49,000
Fluoride	315
Nitrite	578
Boron	105
Phosphorous	<7.5
Total Dissolved Solids	177,000
Aluminum	17.5
Arsenic	0.75
Lead	<0.005
Selenium	1.8
Strontium	163
Zinc	12.6

Source: BEP II, 2002, Section 7.13, AFC Table 7.13-7, and Staff Analysis.
mg/l – milligrams/liter

Blowdown from the HRSG's, the demineralizer system rinses, and in-plant process wastes are all directed to the main cooling tower, to eventually join the wastewater stream that is directed to the brine concentrator. The other wastewater streams are sanitary waste, which is discharged to leach fields, and storm water, which is discussed in the stormwater section of this PSA.

Further discussion of the wastewater system is described in the waste management section of this PSA.

Evaporation Ponds

Wastewater streams from BEP II circulating water processes will be discharged to the BEP II evaporation pond after being concentrated in the brine concentration unit. The concentrated brine will have elevated concentrations of total dissolved solids (TDS) and other non-hazardous constituents; estimated constituent concentrations for the brine discharged to the evaporation ponds are presented in Soil and Water Resources Table 8 (BEP II 2002, Section 7.13). Other wastewater streams from the oil water separator and the reverse osmosis section of the demineralizer unit in the water treatment plant will also be discharged to the evaporation pond (BEP II 2002a, Data Response 68).

The BEP II evaporation pond is designed as a 2-cell pond with a total evaporative area of approximately 7 acres and a total storage capacity of approximately 62 acre-feet (BEP II 2002). The evaporation pond design includes two 60-mil HDPE liners placed on a geosynthetic clay mat with a leak detection system (BEP II 2002). The leak detection system is designed to detect a leak in the inner liner within one hour of a leak occurrence (BEP II 2002).

The Applicant submitted a Waste Discharge Permit Application for BEP II to the RWQCB in May 2002. Neal Krull of the RWQCB indicated that the Waste Discharge Permit Application contained the information required to apply for Waste Discharge Requirements in a May 14, 2002 letter. The evaporation pond capacity identified in the Waste Discharge Permit Application was based on the RWQCB's Waste Discharge Requirements for BEP I. The proposed evaporation pond design, as presented to the RWQCB, has sufficient capacity to store discharge water and 7-10 years of brine sludge and to accommodate: variations in plant inflow, rainfall and evaporation rates; pond maintenance; and a shut down of the brine concentrator and reverse osmosis unit for a minimum of 2-weeks (BEP II 2002).

Storm Water

The relatively flat topography at the site naturally drains towards the southeast. Storm water runoff from upgradient of the BEP I site will be routed in drainage channels to the retention basin in the southeast corner of the site. All non-contact runoff generated on-site will be routed by a network of drainage channels and culverts to the retention basin. The retention basin is intended to capture and percolate all runoff generated by a 100-year event and to prevent potential storm water drainage impacts (BEP II 2002). Retention basin design plans have been reviewed and approved by the City of Blythe.

Storm water drainage from plant process areas will be routed through an oil-water separator and pumped to the evaporation pond. The oil-water separator will receive flows from (BEP II 2002a, Data Response 68):

- Combustion Turbine Transformer areas
- Steam Turbine areas
- HRSG drains
- Chemical Storage areas
- Boiler Feedwater pumphouse floor drains
- Ammonia Unloading area drains
- Fire Pumphouse floor drains
- Maintenance Shop and Warehouse floor drains
- Water Treatment area drain sump

ANALYSIS OF PROJECT RELATED IMPACTS

The analysis of impacts is conducted in a manner consistent with the requirements of CEQA, the Warren-Alquist Act, and the CEC siting regulations.

DIRECT AND INDIRECT IMPACTS

Surface Water

The BEP II site is not located near any natural surface water features and is not within a 100-year floodplain. The BEP II site will be graded to direct surface water runoff to an on-site retention basin designed to accommodate a 100-year storm and prevent runoff from leaving the site. Staff will recommend revisions to the drainage plan to address the need for mitigation of potentially significant adverse flood related impacts.

Groundwater Impacts

Groundwater pumping for BEP II may cause two potentially significant impacts, well interference to nearby existing wells and an increase in PVID's consumptive use of priority 1 Colorado River water.

Well Interference Impacts

Significant well interference impacts occur when a project's pumping causes substantial and unacceptable declines in groundwater levels in existing nearby wells. Power plants are water-intensive operations when water is used for cooling. When groundwater is used for cooling, pumping for power plants cause drawdown that is greater than drawdown for agriculture or residents, relative to the land-use acreage.

The magnitude of well interference is defined by the drawdown of groundwater levels, which radiates from the pumping well forming a 3-dimensional cone of influence. The radial influence and depth of drawdown are determined by five factors: (1) the rate of pumping, (2) the duration of pumping, (3) the depth of the well screens (well construction specifications), (4) the local aquifer parameters, and (5) aquifer boundary conditions. The aquifer parameters include storage, vertical and horizontal hydraulic conductivity, and the thickness of the screened interval of the aquifer.

Aquifer parameters are determined by the layering and thickness of coarse-grained materials, gravel and sand, and fine-grained materials, clay and silt. The composition of aquifers varies widely throughout an aquifer. To accurately determine the impact of pumping specific to the project, calculations of well interference must be based on the aquifer conditions within the vicinity of the pumping wells. Aquifer parameters are best determined by aquifer field tests.

Aquifer field testing has been conducted in the vicinity of the proposed site at BEP I. BEP I conducted aquifer tests on both of the plant's production wells The construction of monitoring wells, supply wells and irrigations wells and aquifer testing at the BEP I has provided detailed information on the aquifer conditions adjacent to the proposed project site. The results of these two tests are presented in two final reports, "Results of the Aquifer Test on Blythe Production Well PW-1, Final Report" (6/18/2003) and "Final Results of the Aquifer Retest on Blythe Production Well PW-2" (5/2003). This testing provides the necessary data to evaluate well interference for BEP II.

Applicant's Analysis of Well Interference Impacts

The Applicant provided an initial analysis in the AFC that evaluates well interference impacts that would be caused by project pumping. The Applicant stated that analysis included an evaluation of the impact of BEP II's pumping at average long-term pumping rates and short-term maximum pumping 4-month summer-peak demand rates. The Applicant based its analysis on the results of BEP I's first aquifer test for project well PW-2 (BEP I 2002). Using a significance threshold of 5 feet drawdown on existing wells, the Applicant concluded that well interference caused by BEP II would have no significant adverse impact on nearby existing wells under long-term pumping conditions and short-term maximum pumping conditions. The nearest well identified by the Applicant, the Sun World well, would only experience 2.2 feet of drawdown, according to the Applicant's analysis. Soil and Water Resources Table 9 summarizes the Applicant's well interference findings for long-term average pumping rates. The Applicant states that drawdown under short-term maximum pumping conditions would be negligible.

Soil and Water Resources Table 9
Results of Applicant's Well Interference Analysis
for Blythe Energy Project Phase 2 (1)

	1000 feet	Sun World Well (4140 feet) (2)
Long-Term Average Pumping Rate (40 years) Drawdown (feet) (2)	Approx 3	2.2

(1) Drawdown data for BEP II impacts: AFC, Section 7.13.1.4.5.
(2) Sun World Well – Identified by Applicant as nearest known well.

Staff has determined that the Applicant's well interference analysis is in error for two reasons. First, the basis of Applicant's analysis, the BEP I's initial PW-2 aquifer test, contained errors and was subsequently rejected by the CEC. Staff determined the test was improperly conducted and the analysis based on these results contained conceptual errors. The BEP I project developer eventually performed successful tests on both its project wells, performed the analyses, and submitted reports that have been accepted by the CEC.

The second error in the Applicant's analysis is the evaluation of short-term maximum-rate pumping impacts. The Applicant evaluated maximum short-term pumping rate drawdown assuming an initial pumping rate of zero; initial zero pumping rate will only occur at the beginning of the project's operations and not during continuous and extended operation. Maximum short-term pumping could occur during any summer during the life of the project and must be evaluated accordingly. Worst case conditions would occur if maximum pumping was required during the latter years of the project. The Applicant has declined to submit a revised well interference analysis for BEP II based on BEP I's approved test results.

Staff Analysis of Well Interference Impacts

In evaluating the significance of the impact of project pumping on nearby existing wells, it is important to recognize that all pumping causes drawdown and some degree of well interference. However, BEP II project pumping would cause drawdown that is greater than drawdown from agricultural or residential water use for comparable land use acreage. The water use-land use ratio for BEP II will be disproportionately higher than other existing water users on the Palo Verde Mesa, and, correspondingly, well interference from the BEP II would be disproportionately large. Currently, groundwater use in the Mesa Verde is very limited and well interference between existing wells would be very small.

For comparison, citrus crops in the Blythe area consume an average of 4.3 acre-feet of water per acre annually (DWR 1986, Snyder 1999). In contrast, BEP II will occupy only 152 acres (BEP II 2002, AFC p7.2-2) and will consume an average of 3,300 acre-feet of water per year. This rate of consumption is equal to about 22 acre-feet of water per acre. This means that the BEP II will consume about 5 times more water per acre than equivalent acreage planted in citrus. Therefore, drawdown from the project wells and the corresponding well interference will be much greater than drawdown for water requirements for typical land uses, so the significant project pumping impacts on nearby groundwater users should be carefully evaluated. Private residential wells may be particularly vulnerable to the impacts of well interference because they tend to be smaller and shallower than agricultural or municipal production wells.

Given the location of the proposed project, the location of existing wells that have been identified, and the results of the BEP I aquifer tests, there are only two adverse impacts that would be likely to occur, as a result of well interference caused by the BEP II groundwater use.

1. Well interference would increase the pumping lift and the corresponding energy costs in nearby wells.
2. Well interference could cause a sufficient decline in the groundwater level in nearby wells that lowering well bowls (pump intake devices) would be required to maintain efficient operation and to prevent equipment damage.

To establish a significance criteria for increased cost of pump lift caused by project well interference, staff compared project well interference for long-term average pumping to well interference that would be generated by providing water to agriculture with a comparable acreage.

To establish a significance criteria for pump damage caused by well interference, staff has referred to Driscoll's "Groundwater and Wells" (1986), which is a standard in the well and pump installation industry. This text recommends that pumps be placed 3 feet below the maximum operating depth of a well, which staff considered along with the 5 feet threshold from the BEP I Final Decision.

Based on an average of the aquifer parameter values calculated by BEP I and a simple Theis nonequilibrium equation method, staff had calculated the well interference impacts that would be caused by BEP II pumping (1) for average long-term (40 years) drawdown and (2) for the maximum pumping rate drawdown. Staff has determined that well interference caused by project pumping would be larger than the Applicant's determination of well interference. The average drawdown at the Thermal King shop well, the nearest well identified by staff, would be 3.8 feet, increasing to 4.5 feet during maximum-rate pumping. Soil and Water Resources Table 10 provides a summary of the results of the staff well interference analysis.

Soil and Water Resources Table 10
Results of Staff Well Interference Analysis for Blythe Energy Project Phase 2 (1)

	1000 feet	2000 feet	Thermal King Well (2700 feet) (2)	1 mile (5280 feet)	2 miles (10560 feet)
Long-Term Average Pumping Rate (1) (40 years) Drawdown (feet)	4.6	4.1	3.8	3.2	2.7
Short-Term Maximum Pumping Rate (1) (4 months) Drawdown (feet)	5.7	4.9	4.5	3.8	2.9

(1) BEP II - Average Pumping Rate = 2,050 gpm (3300 acre fee/year); maximum pumping rate for any four-month period = 2,898 gpm

(2) Thermal King Shop well – Identified by staff as nearest known existing well, located on Hobsonway, southwest of proposed project wells. The Thermal King well is about 2700 feet from the BEP II wells (2575 feet from BEP II PW-1 and 2800 from BEP II PW-2). Distances are based on manual map measurements of Figure 64-1, BEP II response to Round 3 Data Request 64.

Low capacity wells with a limited range of pumping drawdown would be most likely to have shallow pumping settings and would most likely be affected by the well interference produced by BEP II's pumping. Large capacity wells would also experience a decline in groundwater levels caused by project well interference but would be likely to have pump intake placement that would accommodate much larger fluctuation in groundwater levels. Staff assumes that well interference would be unlikely to cause significant adverse impacts to large-capacity water well pumps. However, staff will investigate this assumption prior to the completion of the Final Staff Assessment, and will consider the local well construction practices in the Blythe area.

Water levels in wells located less than 2 miles from the site in the Palo Verde Valley would probably not be affected because groundwater recharge from PVID irrigation with Colorado River water would maintain groundwater levels within the valley. To evaluate the increase cost for pumping lift that would occur for existing wells, staff compared project water use to water consumption for citrus irrigation. Based on average weather conditions in the Blythe area, the 152-acre project site, planted in citrus, would consume about 654 acre-feet of water per year, based on the average evapotranspiration for citrus of 4.3 feet per year (DWR 1986, Snyder 1999). Although the actual pumping rate would be equal to the applied water rate, this analysis assumes that any water that is not consumed by evapotranspiration recharges the aquifer through deep percolation on-site. The following table (Soil and Water Resources Table11) shows the estimated drawdown impacts of pumping if the project site was to be planted with a citrus orchard and irrigated with groundwater compared to the range of drawdown that is likely to occur owing to pumping for the BEP I.

Soil and Water Resources Table 11
Net Drawdown Impact to Nearby Existing Wells (feet)[1]

Annual Water Consumption	1000 feet	2000 feet	1 mile (5280 feet)	2 miles (10560 feet)
BEP II 3,300 acre-feet/year	4.6	4.1	3.2	2.7
Orchard 654 acre-feet/year	0.9	0.8	0.6	0.5
Difference	3.7	3.3	2.6	2.2

[1] Average annual water consumption for irrigation of 152 acres of citrus compared to BEP II water consumption.

This comparison clearly indicates that drawdown and pumping lift caused by groundwater consumption for a typical land use would be minimal as compared to the estimated impact of the groundwater consumption by BEP I.

The increase in energy costs to existing wells caused by project pumping can be calculated with the following formula:

$$\text{KWhr/year} = \frac{(\text{gallons pumped/year})^{(1)} \times H^{(2)}}{162162^{(3)}}$$

(1) Gallons pumped/year by existing well

(2) Change in head (drawdown) in feet

(3) This factor was derived by combining the following two formulas

$$\text{KW input to motor} = \frac{\text{pump bhp} \times 0.7457}{\text{motor efficiency}}$$

$$\text{pump bhp} = \frac{\text{gpm} \times \text{H(in feet)} \times \text{sp.gr.}}{3960 \times \text{pump efficiency}}$$

where: bhp = brake horsepower
gpm = gallons per minute
sp.gr. = specific gravity (water = 1)
H = hydraulic head
Typical pump efficiency = 60%
Typical motor efficiency = 85%

Staff determined that increased costs to residential water users would be nominal; assuming that a household of four uses 1 acre-foot of water annually (about 300,000 gallons/year) and electrical rate of $0.12/KWhr. However, for entities that pump large quantities of water annually, such as agriculture, the cost for increased pumping lift would be proportionately higher. For example, pumping 1000 acre-feet annually with a 2 ½ - foot increase in pumping lift would cost an additional $600/year.

Water Quality

Process Wastewater

Wastewater disposal can lead to soil, surface water, and groundwater degradation and impairment of beneficial uses. Wastewater streams from BEP II circulating water processes, oil water separator, and the reverse osmosis unit will be concentrated in a brine concentration unit and discharged to the BEP II evaporation pond. The concentrated brine will have elevated concentrations of total dissolved solids (TDS) and other non-hazardous constituents as presented in Soil and Water Resources Table 8 (BEP II 2002, Section 7.13). Leaks in the evaporation pond liner system or overtopping could lead to impacts to soil and water quality.

The BEP II will be required to secure Waste Discharge Requirements (WDRs) from the RWQCB before discharging wastewater streams to the evaporation ponds. BEP II must comply with WDRs that regulate evaporation pond capacity, wastewater discharge limitations, monitoring, and reporting for industrial (operational) activities. The Applicant submitted a Waste Discharge Permit Application for BEP II to the RWQCB in May 2002. The RWQCB indicated that the Waste Discharge Permit Application contained the information required to apply for Waste Discharge Requirements in a May 14, 2002 letter.

The proposed BEP II evaporation pond is designed as a 2-cell pond with a total evaporative area of approximately 7 acres and a total storage capacity of approximately 62 acre-feet (BEP II, May 2002). The evaporation pond design includes two 60-mil HDPE liners placed on a geosynthetic/clay mat with a leak detection system (BEP II 2002a). The leak detection system is designed to detect a leak in the inner liner within one hour of a leak occurrence (BEP II 2002a). As a result of the double-contained design with leak detection, the project will have no significant impacts on soil or groundwater resources due to leaks in the evaporation pond.

The evaporation pond capacity identified in the Waste Discharge Permit Application was based on the RWQCB's Waste Discharge Requirements for BEP I. Staff contacted RWQCB staff and confirmed that the evaporation pond capacity requirements identified by the Applicant were appropriate for the BEP II facility (RWQCB 2003).
According to the Applicant's Waste Discharge Permit Application, the evaporation ponds were designed with sufficient capacity to provide (BEP II 2002a):

- Sufficient depth to provide for storage of discharge water and 10 years of brine sludge accumulation.
- Sufficient additional depth to provide for variations in water level due to variations in plant inflow, rainfall, and evaporation rates.
- Sufficient additional depth to provide for an increase in water level due to the evaporation rate falling to 90 percent of the mean evaporation rate for two consecutive years.
- Sufficient additional depth to provide additional storage capacity for a minimum of 2 weeks of increased inflow due to the brine concentrator and reverse osmosis unit becoming inoperable.
- Sufficient depth to provide for increased water level for pond maintenance, assuming maintenance will be required for a 2-month period.
- Sufficient additional depth to account for the 100-year rainfall on top of the maximum water level.
- Sufficient freeboard above the maximum water level to provide the maximum of 24-inches or the height of wind wave run-up plus 12-inches.

However, the Applicant's Waste Discharge Permit Application did not include calculations demonstrating the evaporation pond capacity reported to the RWQCB. The Applicant provided a wide range of evaporation capacity estimates based on a range of possible assumptions, which staff is discussing with the RWQCB.

Staff anticipates that if the BEP II project is able to obtain WDRs from the RWQCB, and operates the ponds in accordance with the WDRs, there will be no significant impacts to water quality (see **Biological Resources** for a discussion of wildlife issues associated with the evaporation ponds). Staff will need draft WDRs to review in order to determine if the proposed project design will comply with LORS.

Sanitary wastewater will be managed and discharged via an on-site septic system and drain field to be designed according to applicable City and County laws. With the implementation of proposed mitigation (refer to the **Mitigation** discussion for more information) and compliance with the proposed condition of certification, no water quality impacts are expected from operation of the drain field.

Storm Water, Erosion, and Retention Basin

Development of roads, buildings, and other paved or impermeable surfaces constructed as part of the project will increase the amount of runoff at the site. This may increase storm water flows and the chances for sediment and contaminants to enter storm water flows and be carried off-site. The drainage plans proposed for BEP II are intended to route storm water runoff from the project site and land upgradient of the site to the project's retention basin. The proposed retention basin is intended to contain and percolate 100-year storm flows and prevent potential impacts related to storm water drainage. Project drainage and retention basin design plans have been reviewed and approved by the City of Blythe, and submitted for staff review (BEP II 2003, Data Response 164).

The storm drainage plans indicate that runoff originating on approximately 1273 acres, including the project site and land upgradient from the project site, will be captured in a series of drainage ditches and routed to the project's retention basin (BEP II, 2002). The 10-year and 100-year 24-hour runoff volumes, 20.3 and 96.6 acre-feet, respectively, were estimated using the rational method taking into account the development on the project site and the land uses upgradient of the project site (BEP II, 2002).

Drainage Channels

Storm water drainage at the BEP II site will be managed through a network of drains, pipes, channels, and culverts. Non-contact runoff from the project site and upgradient land is routed to the retention basin in the southeast corner of the site. Contact runoff from plant process areas will be routed to the oil water separator and then to the evaporation pond. The drainage channel and culvert designs were reviewed and approved by City of Blythe building officials. The drainage channels and culverts were designed to convey 100-year peak flows, and to keep contact runoff separate from non-contact runoff.

Retention Basin Sizing

City of Blythe and CEC requirements indicate that the drainage plans should address a 100-year runoff event, as a result, the proposed retention basin is intended to capture the runoff volume for the 100-year 24-hour rainfall/runoff event. The proposed retention basin is intended to percolate all runoff. The design does not include an outlet structure or an emergency spillway to route overflows away from the containment berm. The Applicant has indicated that the retention basin has a storage capacity of 55 acre-feet and a percolation capacity of approximately 6 cfs or 13 acre-feet per day (BEP II 2003, Data Response 163, 164).

Review of the runoff volume and the retention basin storage and percolation capacities provided by the Applicant indicates the retention basin does not have sufficient capacity to handle the 100-year event. It appears the Applicant has undersized the retention basin by approximately 30 acre-feet. Staff finds that a properly designed stormwater drainage system is necessary to prevent potentially significant impacts.

Given that the proposed retention basin design does not incorporate an outlet structure or an emergency spillway to route overflows away from the retention basin, overtopping of the basin could lead to a catastrophic failure of the containment berm causing significant flooding and erosion impacts downstream of the BEP II site.

The Applicant must demonstrate that the updated retention basin design has sufficient capacity to contain the 100-year event (96.6 acre-feet) and provide for City of Blythe's freeboard requirements. Also, the retention basin design should be revised to include an outlet structure to safely route potential overflows away from the containment berm. The Applicant should revise the Storm Drainage Calculations package (BEP II 2003, Data Request 164) and submit the revised calculations to the City of Blythe and to staff. To ensure that potentially significant stormwater related impacts do not occur, staff must review updated retention basin plans to ensure that the retention basin has been adequately designed to contain a 100-year storm and safely routes potential overflows away from the containment berm.

Groundwater

Staff identified two potential adverse impacts related to groundwater quality that could be caused by the proposed project. First, chemical constituents contained in the project groundwater supply may produce impacts through concentration as cooling water is circulated in the cooling towers and the volatilization of contaminates as they are evaporated during the cooling process. Second, project groundwater pumping could cause movement of hazardous chemicals in the subsurface that could cause increases in chemical concentrations in the project wells or in existing private wells.

The first potential impact, caused by the presence of hazardous chemicals in cooling water, would be air emissions problems resulting in worker safety issues or in exposure issues for downwind receptors. Based on the previous air emission analyses that BEP I performed, BEP I calculated groundwater release rates would be below OSHA exposure levels for ethylebenzene, toluene, total zylenes, and 1,4-dichlorobenzene. Methylene chloride, styrene, and di-2-ethylhexyl-phthalate exceed the maximum daily exposure level. However, these analyses were based on samples from non-project wells and on emission from BEP I alone.

A full review of the most recent sampling from the BEP I production wells will be necessary to update these analyses and to evaluate the combined impact of BEP II and BEP I operations. The Applicant has not yet provided a full report on the 2002 BEP I production well sampling to the CEC. Staff can not complete the analysis of this issue for the FSA without this information.

The second potential impact, caused by the movement of contaminants in the aquifer, could produce changes in groundwater quality in the project well or nearby existing wells. The potential impact that could result from the movement of chemicals in the subsurface is related to source and concentration issues. Although the concentrations of manmade chemicals detected in groundwater sampling reported by BEP I and BEP II met drinking water standards, there is insufficient data to determine the source or distribution of these chemicals in the aquifer.

Project pumping will induce changes in groundwater gradients causing groundwater in the surrounding area to flow towards the project wells. If these chemicals originate from an unreported spill or leak and exist in higher concentrations in the subsurface near the project site, higher concentrations would be drawn toward the project wells and the concentrations in the project water could increase to unsafe levels. Additionally, if nearby existing private wells are located between a contamination source and the project wells, chemical concentrations in the private wells could also increase to unsafe levels. However, it is also possible that the chemicals detected in the groundwater samples represent the maximum level of concentration in the groundwater.

Staff's analysis of potential impacts to groundwater quality is currently incomplete. The Applicant has reported that additional water quality information on the BEP I project wells, sampled in August 2002, is available. Staff needs this information to complete its analysis for the FSA. Based on a review on the August 2002 and all other available data, staff will evaluate the potential impact of BEP II pumping on changes in groundwater quality, as well as the impact of BEP II and BEP I pumping combined.

Linear Facilities

In the AFC, the Applicant indicated that the BEP II facility would be connected to Buck Boulevard Substation constructed as part of neighboring BEP I facility and construction of additional transmission lines off-site will not be necessary (BEP II 2002, Section 6). Also, natural gas would be supplied by the pipeline constructed as part of BEP I facility, and construction of additional off-site natural gas pipelines will not be necessary (BEP II 2002, Section 6). However, in response to Data Requests, the Applicant indicated that either an additional 500-kV single circuit transmission line or an additional 230-kV double circuit transmission line would be required to interconnect the Buck Boulevard Substation to either the Devers Substation or the Midway Substation (BEP II 2003a, Data Responses 195–197 and 227-232).

The Applicant did not provide the discussion of the final routes, construction methods, environmental setting, environmental impacts, and mitigation measures specifically requested by Staff (BEP II 2003a, Data Responses 203). A project description of the final transmission line route will allow staff to complete the analysis of potential erosion impacts related to construction of the additional off-site transmission lines.

Summary of Stormwater and Erosion Control

The Applicant has not submitted a draft operational SWPPP for review. The Applicant indicates the BEP II operational SWPPP will be similar to the BEP I SWPPP. Staff review of the draft operational SWPPP is necessary to fully analyze potential impacts related to storm water runoff, erosion, and soil and groundwater contamination. The construction Draft SWPPP submitted by the Applicant did not address the transmission facilities recently presented in the Data Request/Response phase. Staff needs a complete draft SWPPP that includes the transmission facilities, to include construction staging and laydown areas, for the BEP II project in order for staff to complete its evaluation of impacts.

Staff is recommending that the final construction and operational SWPPPs be provided by the Applicant, and approved by the Energy Commission Compliance Project Manager, prior to the approval of any earthmoving activities. Approval and implementation of these CPM approved plans will mitigate erosion and sedimentation impacts to less than significant levels and will be consistent with the Clean Water Act, and Riverside County and City of Blythe LORS.

Water Conservation Offset Plan

The BEP II project includes a voluntary Water Conservation Offset Plan (WCOP) intended to offset the project's water use by fallowing agricultural lands within the PVID. Agricultural lands located within the Palo Verde Valley that have been actively irrigated within the past 5 years would be eligible for the fallowing program. The potential soil erosion hazard due to wind is generally low within the Valley. Soils in the Valley are generally classified as silty fine to medium grained sandy soils with relatively low erosion hazards. Water erosion hazards are limited in the Valley by the very flat slopes and soils with high permeability and low to moderate runoff potential BEP II 2003, Data Response 170).

The Applicant has indicated the fallowing program would include approximately 1000 acres of land that will be rotationally fallowed on a 5-year cycle with 80% of the land fallowed during any given year (BEP II 2003, Data Responses 170, 171). Implementation of land management measures that have been reviewed and approved by the NRCS and PVRCD and included as an integral part of the WCOP would provide adequate mitigation for potentially significant erosion impacts associated with the planned fallowing program. However, the Applicant has provided no detail with regard to how the WCOP would be implemented, managed, monitored, reported, and verified. Without a complete plan, neither mitigation of potentially significant erosion related impacts nor its effectiveness as a water conservation plan can be determined.

However, staff has determined the use of a WCOP is inadequate as mitigation for the direct and cumulative impacts related to the use of Colorado River groundwater by BEP II. Therefore, staff has analyzed other measures that could mitigate or eliminate the project's impacts in the alternatives study in Soil and Water Resources Appendix A.

BEP II Direct Impacts to the PVID Water Supply

It is important to have a fundamental understanding of Colorado River water supply and allocation issues, as these issues are central to the evaluation of BEP II's proposed use of groundwater that will be replaced with Colorado River water (Colorado River groundwater).

Background

The issues involved with the use of Colorado River water, particularly those involving river water derived from the mainstream via underground pumping, are many and complex, and require a somewhat detailed discussion for the purpose of evaluating impacts. Staff has provided a discussion of those issues considered most relevant in order to explain what information was considered. The reader is encouraged to review the original documents and ancillary materials comprising the Law of the River, and other materials referenced in this section.

The U.S. Supreme Court decree, 1964, Arizona v. California defines the responsibility of the Secretary of the Interior to account for consumptive use of water from the mainstream of the Colorado River. The decree contains the following provisions, among many others, regarding consumptive use:

> “*”Consumptive use” means diversions from the stream less such return flow thereto as is available for consumptive use in the United States or in satisfaction of the Mexican treaty obligation.*”

> *“”Mainstream” means the mainstream of the Colorado river downstream from Lee Ferry within the United States, including the reservoirs thereon.”*

> “*Consumptive use from the mainstream within a state shall include all consumptive uses of water of the mainstream, including water drawn from the mainstream by underground pumping, and including but not limited to, consumptive uses made by persons, by agencies of that state, and by the United States for the benefit of Indian reservations and other federal establishments within the state*

The requirement for a contract to use Colorado River water is described in part, as:

> “*…mainstream water shall be released or delivered to water users (including but not limited to, public and municipal corporations and other public agencies) in Arizona, California, and Nevada only pursuant to valid contracts therefore made with such users by the Secretary of the Interior, pursuant to Section 5 of the Boulder Canyon Project Act or any other applicable federal statute….*”

The Decree requires the identification of the users of Colorado River water and publication of the quantities of diversion and consumptive use stated for each diverter, point of diversion, and each State.

As discussed previously, the accounting-surface method is being used for identifying wells that yield water that will be replaced by water from the river. The development of this accounting process to identify wells pumping Colorado River water is currently in-progress by the United States Bureau of Reclamation, Lower Colorado River Region (USBR), however, it is not known when it will actually be generally implemented. The accounting surface represents the water table of the river aquifer that would exist if the only source of water to the aquifer were the river. Wells completed in the river aquifer between the boundaries of the flood plain and river aquifer with a static (nonpumping) water level at or below the accounting surface are presumed to produce water that will be replaced by Colorado River water.

The USBR has made its position on this issue very clear in a series of letters on the issue of whether the water the BEP II project intends to use is Colorado River water. In a letter to the Energy Commission dated June 14, 2002 (USBR, 2002), the USBR stated that:

> “Reclamation’s responsibility to administer the use of Colorado River water in the states of Arizona, California, and Nevada is based on key provisions in the 1928 Boulder Canyon Project Act and the 1964 Supreme

Court Decree in the case of Arizona v. California (Decree) as well as the priority system recommended by the 1931 California Seven-Party Agreement which was adopted by Federal regulation in 1931. Each year Reclamation accounts for diversion, consumptive use, and return of Colorado River water by diverter and by state. The Supreme Court Decree defines consumptive use to include diversion from well pumping."

"Reclamation considers all wells in the lower Colorado river floodplain and wells within the accounting surface with a static water level equal to or less than the river's elevation to be utilizing Colorado River water for accounting purposes."

The Colorado River Board (CRB) of California was established by State statute to protect California's rights and interests in the resources provided by the Colorado River and to represent California in discussions and negotiations regarding the Colorado River and its management. The CRB considers the water BEP II will use to be Colorado River water, and has stated the CRB's position regarding requirements related to the use of this water in a letter to Energy Commission dated November 15, 2002 (CRB, 2002):

"As stated in the Boulder Canyon Project Act (45 Stat. 1057), any user of Colorado River water has to have a contract with the Secretary of the Interior through the U.S. Bureau of Reclamation (Reclamation) to divert and consumptively use Colorado river Water. According to the 1964 U.S. Supreme Court Decree in Arizona v. California, this contract requirement applies to all diversions made from the Colorado River, whether made directly from the River or via groundwater well withdrawing water from a aquifer which is hydraulically connected to the Colorado River, i.e., the water pumped from a groundwater aquifer will be replaced with water from the Colorado River."

"Any well within the "accounting surface" is deemed to be pumping groundwater from the aquifer which will be replaced by the Colorado River water. BEP II wells are within this "accounting surface"."

In response to a CEC request for information, the CRB once again confirmed in a letter to Terrance O'Brien of the CEC from Gerald Zimmerman of the CRB dated September 11, 2003 (CRB 2003), the BEP II project's use of Colorado River water:

"The fact that BEP II would pump groundwater from a depth deeper than the U.S. Bureau of Reclamation/U.S. Geological Survey (USGS) established accounting surface constitutes a presumption that such water is considered to be Colorado River water for accounting purposes in the eyes of Reclamation and the CRB. The implication is that pumped water would be replaced with water from the Colorado River."

The Applicant has agreed with staff, the USBR, and the CRB that the BEP II project well(s) will be completed within the accounting surface (BEP II 2003, Response to Staff Data Request 142).

Staff finds the available scientific and technical data reviewed earlier in this document, when considered in concert with the USBR and CRB agency determinations, fully support the hydraulic connectivity of the groundwater the BEP II project intends to use with the mainstream flow of the Colorado River. Staff concurs with the PVID, USBR and CRB, as does the Applicant, that the project's water will be obtained from wells encountering the USGS/USBR accounting surface defining the Colorado River aquifer (BEP II 2003, Data request 142).

Therefore, staff finds it necessary to assess the project's use of groundwater that will be replaced with Colorado River water as part of both the local and regional water supply.

Applicant's Position on BEP II use of Colorado River Groundwater

Staff has not been able to obtain over three rounds of Data Requests any description of the implementation and operation of the WCOP of sufficient detail to allow for an assessment of its effectiveness as an actual water mitigation measure that would quantitatively mitigate the projects consumptive use of water. The Applicant has provided only a brief description or scope of what the WCOP is to accomplish, which is completely inadequate to determine how or if it would actually work and/or be effective at conserving an amount of water equal to the BEP II projects consumptive use. The Applicant's statements in their responses to Data Requests establishes their position on the use of Colorado River groundwater and the purpose of the WCOP. The Applicant has provided the following responses to Staff Data Request 198 (BEP II 2003a):

Applicant Statement 1 "We agree that under CEQA Staff should evaluate any potential physical changes in the environment that would be caused by implementation of the voluntary WCOP. Staff further states in the background that the purpose of the WCOP is to conserve the same amount of water as BEP II will consume for all purposes, including wet cooling. As has been stated at numerous workshops and previous data requests, this statement is an oversimplification of the history, development and purpose of the WCOP. Please see the Response to Data Requests 142."

Applicant Statement 2 "With respect to Staff's request for information describing the implementation, management, monitoring, reporting and verification procedures proposed, Caithness Blythe II, LLC (CB II) offers the following to address Staff's concern specifically related to the potential physical changes to the environment from implementation of the WCOP. In our opinion the only potential physical changes to the environment that we have been able to evaluate relate to the potential loss of prime agriculture land or the potential to cause soil loss through fallowing."

Applicant Statement 3 "We do not understand why Staff continues to want to substitute its opinion for the Colorado River system expert."

The Applicant's response to Staff Data Request 142 includes the following statements:

Applicant Statement 4 "The Blythe 2 project will use groundwater, and will not utilize any surface water supplies."

Applicant Statement 5 "Reclamation is the Supreme Court appointed Water Master for allocation of surface water from the Colorado River. A complex set of laws and regulations, collectively known as the Law of the River, govern surface water entitlements to Colorado River waters, a full discussion of the Law of the River has been added to the Application for Certification (AFC) text and LORS tables, as requested during data adequacy review. BEP II project will rely upon groundwater, and does not propose to use any surface water."

Applicant Statement 6 "However, Reclamation has indicated that it believes it can extend its regulatory authority under the Law of the River to all Mesa well users, and that it is likely to do so in future years."

Applicant Statement 7 "Since groundwater pumping for the Blythe Energy Project will encounter the Accounting Surface as defined by Reclamation, Reclamation has suggested that this use of water, and all other Mesa groundwater users may be accounted for at some undefined time in the future as part of PVID's Priority 3 surface water entitlement. For that reason, and to ensure that the power plant project does not impact PVID, the Blythe energy Project, and now BEP II, each voluntarily agreed to implement WCOPs."

Staff Analysis of the Applicant's Position and Proposed Project

Staff finds the Applicant's project design and operational plan are apparently based on the following presumptions:

Argument 1 BEP II believes the project is using groundwater, not Colorado River water.

Staff disagrees with the Applicant, as does the USBR, the CRB, CVWD, and the PVID. The water the project intends to use is consistent with the legal definition of Colorado River water contained in the Law of the River (The Arizona v. California U.S. Supreme Court Decision of 1964), i.e., "Consumptive use from the mainstream within a state shall include all consumptive uses of water of the mainstream, including water drawn from the mainstream by underground pumping…."

Staff has reviewed the available hydrogeological technical data and determined the groundwater the project will use is water that will be replaced by Colorado River water, and is, therefore, considered to be Colorado River water. The USBR/USGS accounting surface reasonably defines the groundwater zone where pumped groundwater will be replaced with Colorado River water. Therefore, staff concurs with the position taken by the USBR (USBR 2001, 2002, 2002a, 2003), the CRB (CRB 2002, 2003). CVWD (2003) and the PVID (PVID 2003, 2003a, 2003b) that the water the project will use is Colorado River water. Furthermore, in the Commission Decision for the BEP I project (Energy Commission Docket No 99-AFC-8) it was determined that:

> "Staff and the Applicant agree that the groundwater the project plans to use is primarily derived from the Colorado River through the Colorado River aquifer."

Additionally, an ineffective WCOP will result in "potential physical changes in the environment" by decreasing the physical volume of groundwater returned to the PVID agricultural return drains by the amount of water consumed by BEP II. Groundwater that is not returned to the drains will not be returned to the Colorado River. Water that is not returned to the Colorado River will not be credited to the PVID under the diversion less return accounting system in current use by the USBR; it will be counted against the PVID as a consumptive use.

Argument 2 BEP II believes the project will have no unmitigated significant impacts.

Staff finds the BEP II projects unnecessary and potentially unauthorized use of Colorado River water to be a contribution by the BEP II project to a significant cumulative impact to both the water resource and to its users. Any unauthorized use of PVID's Colorado River water allocation is a direct significant impact to the PVID water supply and its users. Avoidance of the impact and/or mitigation for the project's direct, indirect, or cumulative significant impacts is required under CEQA. With or without an effective WCOP the BEP II project's use of Colorado River groundwater will contribute to an existing significant cumulative impact to the Colorado River water supply and the users of this resource.

Argument 3 BEP II believes staff should evaluate physical changes in the environment related to the WCOP to include only impacts to prime agricultural land and impacts from erosion on the fallowed lands, and not water conservation or mitigation of the project's water use.

Staff agrees physical changes in the environment must be evaluated, and has done so in this PSA. For any actual or potential impacts that are identified, mitigation must be developed, implemented, monitored, reported, and verified for effectiveness in accordance with CEQA. Mitigation for potentially significant impacts is discussed under Staff's Proposed Mitigation, Applicant's Proposed Mitigation, Conclusions and Recommendations, and Proposed Conditions of Certification. Staff has determined the consumptive use of Colorado River groundwater by the project has associated significant impacts that require either mitigation or elimination under CEQA.

Argument 4 The Applicant has not identified any significant impacts associated with the consumptive use of Colorado River groundwater. BEP II does not appear to have offered the WCOP as mitigation for the project's consumptive water use, or for quantitative conservation of water.

As described in **Applicant Statements 1** and **7,** the WCOP does not appear to be offered as mitigation for the project's water use. For reasons of thoroughness, staff has evaluated the WCOP as a quantitative mitigation measure to mitigate the project's use of Colorado River groundwater. The WCOP contains no implementation plan. Even if the WCOP is offered as mitigation for the project's water use, it does not provide sufficient detail to allow it's effectiveness as a quantitative water mitigation measure to be determined. Discussion of procedures for the implementation, monitoring, reporting, and verification of the effectiveness of the proposed measures to be employed in the plan, or demonstration of the actual effectiveness of the mitigation measures is inadequate and/or not provided. Staff's position is consistent with the purpose of a quantitative water mitigation measure.

Staff is unsure of the meaning of the term "oversimplification" used in **Applicant Statement 1**. It is staff's position that any proposed water mitigation program must be able to demonstrate a quantitative mitigation of water of the amount of water the project will consume. However, simply offsetting the project's use of Colorado River groundwater is inadequate mitigation for the project's impacts related to the consumptive use of Colorado River groundwater.

Argument 5 The USBR is the deciding authority in matters of both the WCOP and the Colorado River; therefore, Energy Commission Staff should have no say in determining the efficiency of the WCOP.

The CEC is sole licensing agency and authority for the BEP II project as a power plant in the State; the USBR has no authority to license power plants in the State. The CEC is the sole agency having responsibility for administering the Warren-Alquist Act, enforcing the CEC power plant siting regulations deriving from the Act, and is the designated lead agency for administering the California Environment Quality Act for the BEP II project.

In the CEC licensing proceeding, the USBR status is limited to that of a responsible agency with the authority to enforce applicable laws, ordinances, standards, and regulations subject to their jurisdiction. The USBR has no jurisdiction or authority to perform environmental assessments related to licensing power plants in the State. Any requirements or mitigation that may be acceptable for the USBR for its purposes may or may not be acceptable to CEC for its purposes under CEQA and Warren-Alquist.

Of particularly serious concern to staff is the fact that the USBR completely reversed itself on the BEP I WCOP by first approving it (USBR 2000a) prior to licensing, and then retracting its approval (USBR 2001) after the project was licensed due to the unacceptable manner in which it was implemented by BEP I that in the USBR's opinion, will result in an unauthorized use of Colorado River water. This situation is apparently still unresolved to the satisfaction of the CRB and the USBR. Staff finds, as discussed below, that while the USBR requirements for an effective WCOP may be adequate for USBR purposes, they are not adequate as demonstrated effective mitigation for significant impacts under CEQA.

Analysis of PVID Direct Impacts

Staff has considered the available hydrogeological data as it relates to the surface-groundwater system of the Palo Verde Valley, the Mesa, and the Colorado River. Staff has conducted a number of conference calls with representatives of the PVID in an effort to better understand any potential impacts to the PVID resulting from the project's proposed use of groundwater replaced with Colorado River water (Colorado River groundwater). The Record of Conversations (ROC) for these discussions have been docketed after review and approval by all parties participating in these discussions. Staff has determined the PVID's position to consist of the following principal elements:

- PVID considers the groundwater aquifer from which the Applicant proposes to withdraw including both water under the Mesa and the Valley, to be water that would be used under PVID's water right (CEC/PVID 2003).
- PVID believes that the Applicant could continue with its plans to withdraw groundwater at the BEP II site, and that doing so without the WCOP, is in essence using PVID's water supply as accounted for by USBR. Even with the WCOP, PVID considers the groundwater that would be withdrawn by BEP II and consumed would still be an exercise under PVID's water right (CEC/PVID 2003).
- The current rate at this time for which PVID would expect to charge BEP II for water is $85/AF (CEC/PVID 2003).
- In a May 18, 2000 meeting regarding BEP I between Blythe Energy (BEP I), PVID and USBR, the parties agreed the BEP I project (on the Mesa) also lies over groundwater that is included within the western extent of the Colorado River accounting surface (BEP I Response to Data Request 121 dated May 26, 2000). In the case of BEP II, although the Applicant is representing that its proposed water supply is not Colorado River surface water (BEP 2003, Response to Data Request 177), the USBR and USGS maintain that the BEP II groundwater is part of the Accounting Surface, Water Resources Inventory Report 94-4005, USBR 2002) (CEC/PVID 2003a).
- On page 7.13-4 of the AFC, the Applicant represents that the BEP II groundwater may be accounted for at some undefined time in the future as part of PVID's surface water entitlement. PVID's position is that any groundwater withdrawal would be immediately accounted for as part of PVID's surface water entitlement on a volume equivalent basis (BEP II Use = PVID's Incremental Use attributable to BEP II), as it will be reflected as a net decrease in its gauging of Return Flows to the Colorado River, subject to the conservation effects of the WCOP. PVID has no problem with accounting for BEP II's water use (CEC/PVID 2003a).
- PVID's contract with the USBR dated February 7, 1933 specifies that in addition to entitlements for Priority 1 water supply, that PVID is also entitled to Priority 3 water supply from the Colorado River for use exclusively on 16,000 acres in the area known as the Lower Palo Verde Mesa (Mesa) for beneficial consumptive use (CEC/PVID 2003b).
- PVID is entitled to divert Priority 1 and 3 water at the Blythe Intake on the Colorado River without charge, and is responsible to convey water for use within its District. PVID believes that its Priority 1 and 3 water is not limited to a single purpose of use such as for only irrigation, but rather can be applied for any beneficial consumptive use including industrial purposes.
- PVID believes it has entitlement through its Priority 3 allocation to supply water to BEP II. This water could be conveyed either from its irrigation or drainage canals extended with a pipeline to BEP II, or by groundwater pumping directly from the BEP II site (CEC/PVID 2003b).

- PVID believes some groundwater under the Mesa is recharged by irrigating on the mesa with canal water pumped from the valley and by under flow from valley groundwater, drains, and canals. Valley groundwater is further augmented with Colorado River water by the irrigation applications within PVID's district which percolate to groundwater (CEC/PVID 2003b).
- PVID believes that any groundwater withdrawn by BEP II would be accounted for indirectly by reducing PVID's return, and in essence is a utilization of PVID's Priority 3 water (due to the proposed location of use by BEP II being on the Mesa) (CEC/PVID 2003b).
- PVID is of the opinion that a water supply contract between the BEP II Applicant and itself would be a more straight-forward way of accounting for BEP II's water use (CEC/PVID 2003b).

Hydrogeologic Evaluation of Groundwater Use Impacts to PVID

As discussed previously, groundwater pumping for BEP II will yield water that will be replaced by Colorado River water. Under current conditions, the only significant source of recharge to the aquifer beneath the Palo Verde Valley and Mesa comes from the Colorado River. The aquifer beneath the Palo Verde Valley is recharged from percolation from irrigation water diverted from the Colorado River and delivered by PVID and from direct underflow from the Colorado River. Most of the groundwater recharge to the aquifer beneath the Palo Verde Mesa comes from lateral underflow from the Valley. The high groundwater levels in the Valley, which are maintained by PVID irrigation with Priority 1 Colorado River water, provide a constant-head source of recharge to the aquifer beneath the Mesa.

Project pumping will produce a chain of responses through the aquifer system. Beginning at the project site, groundwater pumping will produce a cone of depression that will extend from the wells to the Palo Verde Valley, located 1 mile east of the project. BEP II pumping will create a groundwater gradient that will induce lateral underflow from the high groundwater table beneath the Palo Verde Valley to the project wells. Once drawdown and groundwater gradients for the BEP II wells stabilize, the rate of induced underflow from the Valley will be equal to the project pumping rate of 3,300 acre-feet/year. Induced underflow from the valley represents the first step in the chain of groundwater response.

The second step in the process, groundwater recharge from PVID irrigation in the valley will increase by 3,300 acre-feet/year in response to the increase in lateral underflow to the Mesa. Correspondingly, the increase in groundwater recharge from irrigation will decrease the discharge of excess irrigation water to the PVID drainage ditches and return flows to the Colorado River by 3,300 acre-feet/year.

PVID's consumptive use, based on the legal definition of consumptive use (U.S. Supreme Court decree, 1964, Arizona v. California, Article I), is defined as diversions from the river minus return flows. Therefore, BEP II's consumptive use of groundwater will be attributed as an increase in PVID's consumptive use of its Priority 1 Colorado River water right.

Effectiveness of the Proposed WCOP as Mitigation for BEP II's Water Use

Staff has evaluated the Applicant's WCOP as a quantitative mitigation measure for impacts related to the project's use of Colorado River groundwater, and determined what has been presented to be inadequate as a mitigation measure. The WCOP contains no detailed implementation plan, no detailed management plan, no detailed monitoring component, no detailed reporting component, and no detailed independent verification component. What the Applicant has provided constitutes nothing more than a scope of work or abstract of an actual complete and functional plan.

Furthermore, the Applicant has not proposed the WCOP with the intent of eliminating the project's consumptive use of Colorado River groundwater. It would only displace water from an agricultural use for consumptive use by the project, and the project would still consume about 3300 AFY of Colorado River groundwater for cooling. The WCOP does not quantitatively mitigate or eliminate the project's use of Colorado River groundwater water, and would not meet CEQA requirements for an effective mitigation measure for the impacts identified by staff. Additionally, it would not provide conformance to applicable LORS.

The Applicant's WCOP includes the following principal components:

- The project wells will be equipped with recording meters to record the volume of water pumped.
- BEP II will acquire, through purchase or lease, lands on the Mesa or the Palo Verde Valley floor that are within the Palo Verde Irrigation District and are actively irrigated (within the past five years). These lands will be rotationally fallowed or retired from all uses that depend upon Colorado River water.
- A consumptive water use volume of 4.2 acre-feet per acre will be used as the accounting basis for this intra-basin and intra-district accounting offset.
- BEP II will report their groundwater pumping and document the acreage of land retired from irrigation to Reclamation and PVID annually. Reports for a given year must be sent to Reclamation and PVID by January 31st of the following year.
- If the land retired or fallowed was previously served by surface water, a report will include a PVID record from its water delivery data base showing that no water was delivered to the particular fields.
- If a particular delivery point serves an area greater than the fallowed area, or if the land being retired or fallowed was previously served by groundwater, photographic evidence will be included in the report to confirm that crops are not growing on the field.
- The WCOP shall be implemented concurrent with commercial operation of the power plant, and will remain in effect for the life of the power plant.

Staff has reviewed the fallowing plans that have been either actually used or proposed within the PVID by MWD, and carefully considered what other components would be necessary for any WCOP to provide a reasonably quantitative offset of the project's water use. While the Applicant's WCOP contains several useful components that should be included in a water conservation plan, it is deficient in certain critical areas that include detailed discussion of requirements for implementation, monitoring, reporting, verification, and accountability of third-party contractual participants. In addition to what the Applicant has proposed, staff considers the following components to be a necessary part of any quantitative water conserving program:

- A complete WCOP that provides a detailed description of how all aspects of the program will be implemented, administered, and independently monitored and verified.
- The lands included in the WCOP must have a recent irrigated agricultural crop production use defined as having been used for irrigated agriculture for any 4 of the last 5 years. The WCOP must contain the criteria for selection of the lands to be fallowed, it must specifically identify the lands considered for inclusion in the program, and it must demonstrate that these lands meet the criteria for inclusion in the WCOP.
- PVID “Water Toll” acres must be used to calculate acreage included in the program, and to verify that the acreage included in the WCOP meets the requirements for recent irrigated agricultural production within any 4 of the last 5 years. The crop production history and PVID water toll data for all acreage included in the program must be included for the most recent 5 year period at the time the acreage is included in the WCOP.
- The WCOP must ensure that additional lands would not be put into production by the same landowner participating in the WCOP by fallowing land, or by other land owners within the PVID.
- A water conservation figure of 4.2 acre-feet per acre of fallowed land will be used for calculating WCOP fallowing requirements.
- The WCOP must include a provision excluding lands from participation in the WCOP that are being scheduled for fallowing as part of the agricultural production cycle to ensure actual water conservation.
- The WCOP must preclude lands participating in the fallowing program from being developed or put to other uses that may consume water. The WCOP must address the need for fallowing additional lands should activities involving consumptive uses of water occur on lands included in the fallowing program.
- An agricultural soil conservation plan consistent with National Resource Conservation Service guidelines and recommendations specific to the Blythe area and Palo Verde Irrigation District must be developed and included in the WCOP to ensure that the fallowing program has no adverse impacts on the agricultural capacity of the soil, and that wind, stormwater, or other erosion related impacts do not occur.
- A contract and/or agreement with participating landowners must be developed as part of the WCOP to insure that lands included in the WCOP meet required specifications, and that participating landowners meet contractual performance requirements. This contract must be reviewed and approved by CEC staff.
- The WCOP must include an independent monitoring, reporting, and verification component that ensures that the requirements of the WCOP are properly

implemented, monitored, verified, and reported at the Applicant's expense. The development of an acceptable contract with an independent third party subject to CEC legal staff review and approval would be required. This contract must be reviewed and approved by CEC staff.

However, even an effective WCOP would not provide adequate verifiable mitigation of the project's cumulative impacts under CEQA.

Finding of PVID Direct Impact

Upon review and consideration of PVID's position on the issue of BEP II using groundwater that will be replaced with Colorado River water, staff's review of the Applicant's WCOP, the available hydrogeological technical data, and the USBR and CRB position that BEP II's water use should be accounted for against PVID's Colorado River water right (refer to the Cumulative Impacts discussion below), staff makes the following findings:

- The BEP II project is within the accounting surface used by the USBR and accepted by the USBR, the PVID, and the CRB as a groundwater zone that defines groundwater that will be replaced with Colorado River water, and is within the PVID boundary.
- Staff is in agreement with the PVID, the USBR, and the CRB that the water the project will use is both legally and hyrogeologically defined as water that will be replaced with Colorado River water.
- The PVID, USBR, and CRB consider this water to be accountable under PVID's Colorado River water right.
- The PVID's Colorado River allocation is calculated and accounted for based on diversion less return.
- BEP II has neither developed a sufficiently detailed WCOP, nor has BEP II demonstrated the ability of the WCOP to quantitatively conserve the same amount of water the project will consume.
- BEP II will be pumping and consuming water that would normally be accounted for and credited to the PVID as return flows to the Colorado River, i.e., water that would not be consumptively used except for BEP II.
- Decreased return flows to the Colorado River resulting from the BEP II project's consumptive use of this water without mitigation represents could be considered an unauthorized use of PVID's Colorado River water right, and represents water that would be unavailable to the PVID and its water users. Such a change in the volume of water returned to the river is a significant direct impact to the PVID's Colorado River water supply when diversion less return accounting of water use within the district is considered. Mitigation of this significant direct impact to less than significance, or elimination of the impact is required under CEQA.
- In PVID's opinion, a water supply contract agreeable to both BEP II and PVID offers a more direct, verifiable, and equitable means of providing water to the project and accounting for the project's water use; it would provide adequate mitigation for the

direct significant impact to the PVID's Colorado River water right, but not for the projects impact on the State's Colorado River water supply and its users.

∉ There is some uncertainty requiring further evaluation regarding whether or not the PVID can provide water to the project using such a contract in a manner consistent with the PVID/USBR water delivery contract for Colorado River water (PVID/CMYH 2003, CRB 2003, CVWD/RS 2003). However, this does not appear to an issue for the USBR, since it has accepted the use Colorado River groundwater for power plant cooling by approving WCOPs for both BEP I and BEP II.

A WCOP demonstrated to be effective may be capable of mitigating direct impacts to PVID and it's water users, however since it would not mitigate the project's use of Colorado River groundwater, the cumulative impacts to the State's Colorado River water supply and its users discussed below would remain unmitigated. Other water supply and cooling options have been analyzed by staff in the Water Supply and Cooling Options study in Appendix A, and staff recommends an alternative cooling alternative project design that will provide mitigation of the BEP II impact to the PVID water supply and its users.

CUMULATIVE IMPACTS

California's Water Supply

California is currently experiencing a statewide shortage of fresh surface water. Ground water is also being extracted from many aquifers at a rate greater than the aquifers are being recharged. These conditions are causing an overdraft of fresh water that will continue for the foreseeable future. Because of this water shortage the State has been using Colorado River water in excess of its entitlement of (often exceeding it by over 800,000 acre-feet per year). The amount of Colorado River water that California receives will be reduced to California's legal entitlement of 4.4 million acre-feet per year (MAFY).

To gain a perspective of existing and projected statewide shortages of fresh water supplies, a number of reports and publications help illustrate the challenges facing California now and in the future:

1. DWR's California Water Plan Update 1998 – Every five years DWR is required to prepare a statewide Water Plan addressing projected demands and supplies, and strategies to meet the state's future water needs. In the last completed Water Plan Update -1998, DWR determined that as of 1995, a 1.6-million afy shortage of water supply existed in California. In 2020, the shortage is projected to be 2.4 million afy DWR 1998).

2. DWR's California Water Plan Update 2003 – DWR has begun to update its assessment of the state's water supplies and demands with its California Water Plan Update 2003. This new plan will look more broadly than before at programs and conditions affecting the State's water resources. These programs will include evaluating the status and interaction of CALFED, the Colorado River Water Use Plan, the Central Valley Project Improvement Act (CVPIA), the State Water Resources Control Board Bay-Delta water rights hearings, hydroelectric project

relicensing, and global warming, among other programs and conditions (DWR 2002b).

3. DWR's SWP Delivery Reliability Report –The analyses contained in DWR's Final SWP Delivery Reliability Report conclude that the SWP, using existing facilities and operated under current regulations, can deliver an average between 70 and 75 percent of the primary contractual supply (defined as the Table A amount), now and in the future. During dry periods, deliveries are projected to be significantly lower. For example, if conditions similar to 1977 were to repeat, SWP deliveries are projected to be about 20 percent of the primary contractual supply (DWR 2002c).

4. California Colorado River Water Use Plan – California is charged with bringing its use of Colorado River Water in line with its allocation. California's normal apportionment is 4.4 million acre-feet/year, and at times the state has used up to 5.4 million acre-feet/year (CRB 2000).

5. Global Warming – Scientists are recognizing changing trends in our atmospheric conditions that are already showing effects on our water supplies in California. Over the past century, land and sea temperatures have risen by about 1°F. Since 1958, carbon dioxide levels have increased from about 315 parts per million (ppm) to about 370 ppm. Water originating from mountain snowmelt has diminished by about 12 percent in the Sacramento River system over the last century. The effect is compounded by more intense and earlier snowmelt. This reduces the amount of water that can be diverted for use and storage later in the year (Knowles and Cayan 2002).

Cumulatively in California, fresh water supplies for consumptive uses are diminishing while the demand for fresh water is increasing. CALFED and the CVPIA Programs have achieved significant progress in environmental protection of sensitive or endangered species and restoration of aquatic habitat in the Delta and its watershed. This has resulted in more water appropriated for environmental needs and less water available for consumptive needs.

Hydropower and water supply projects are experiencing reallocations during license renewals resulting in less water storage for future consumptive needs. On a Statewide basis the DWR has determined that a 1.6-million afy shortage of water supply exists in California. North Coast and San Francisco Bay Regions are not expected to experience future shortages during average water years but are expected to see shortages in drought years. Most of the State's remaining regions experience average year and drought year shortages now, and are forecasted to experience increased shortages in 2020. The largest future shortages are forecasted for the Tulare Lake (including Kern County) and South Coast Regions, areas that rely heavily on imported water supplies. These regions of the State are also where some of the greatest increases in population are expected to occur (DWR 1998).

Californians have experienced drought year shortages during the most recent droughts (especially in 1991 and 1992). Urban residents faced cutbacks in supply and mandatory rationing, some small rural communities saw their wells go dry, agricultural lands were fallowed, and environmental water supplies were reduced. By 2020, without additional facilities and programs, these drought year conditions will worsen (DWR 1998).

Future water shortages have direct and indirect economic consequences. Direct consequences include costs to residential water users to replace landscaping lost during droughts, costs to businesses that experience water supply cutbacks, or costs to growers who fallow land because water supplies are not available. Indirect consequences include decisions by businesses and growers not to locate or to expand their operations in California, and reductions in the value of agricultural lands. Other consequences of shortages are less easily measured in economic terms--loss of recreational activities or impacts to environmental resources, for example (DWR 1998).

The project's proposed use of fresh water would add approximately 3300 acre-feet per year of new demand on California's fresh water resources. This is enough water to meet the domestic water needs of approximately 5000 families (17,200 people) for one year. It is enough water for the domestic water needs of the entire population of cities such as El Segundo or Susanville, or the entire population of either of the counties of Inyo or Trinity for an entire year. If a 30-year operational life is assumed for BEP II, the project will consume through evaporation approximately 100,000 acre-feet of Colorado River groundwater over its lifetime.

Statement of Counsel

California Constitution, Article X, Section 2

Requires the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and that the waste or unreasonable use or unreasonable method of use of water be prevented, and that the conservation of such waters is to be exercised with a view to the reasonable and beneficial use thereof in the interest of the people and for the public welfare.

Staff has considered the question of whether the use of fresh water for power plant cooling constitutes waste or an unreasonable use or fails to appropriately conserve the state's waters when there are feasible alternatives. Staff has concluded that it does. We base our conclusion on a number of Water Code provisions, on SWRCB policy, and on CEC Integrated Energy Policy Report (IEPR) Water Policy. Although we understand that this is a legal issue, which is usually not addressed in technical analyses, we have included a summary of our understanding of the legal issue in order to provide a brief explanation of why our testimony focuses on whether there is a feasible alternative to the use of fresh water for cooling in this case. As such, the following three paragraphs are not being offered as testimony, but as a statement of counsel explaining the basis of staff's conclusion regarding the need for use of an alternative water source or cooling technology option.

Specifically, the Legislature has found that the use of potable domestic water for nonpotable uses, including industrial uses, is a waste or an unreasonable use of the water within the meaning of the Constitutional provision, provided that the SWRCB has found that there is recycled water available that is of adequate quality, available at a reasonable cost, does not cause health impacts or adversely affect water rights (Water

Code section 13550). Similarly, Water Code section 13552.6(a) states that the use of potable domestic water for cooling towers is a waste or unreasonable use within the meaning of the Constitutional provision if the SWRCB determines that recycled water is available that meets the conditions articulated above.

These statutes evince a strong legislative policy against the use of fresh water for nonpotable uses where feasible alternatives are available. And, although the SWRCB is not being asked to determine whether the Water Code standards are met in this case, staff believes that the Energy Commission, whose license is in lieu of all other state permits, can and should make the same determination in its siting cases. For further guidance, staff refers to Water Code section 13146, which directs other state agencies to "comply with state policy for water quality control unless otherwise directed or authorized by statute. . ." Thus, where there is an alternative to the use of fresh water for powerplant cooling that is economically, environmentally, legally, and technologically feasible, the Commission should disallow the use of fresh water for that purpose.

For further support of our conclusion that the use of fresh water for power plant cooling is a waste or unreasonable use and does not serve to conserve the state's waters, we look to SWRCB policy. Resolution 75-58 establishes priority for sources of cooling water for power plants, with high-quality inland water being the lowest priority. The Resolution also states that "[w]here the Board has jurisdiction, use of fresh inland waters for powerplant cooling will be approved by the Board *only* when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound" (Emphasis added). It is important to note that in May 2002, the Chair of the State Board sent a letter to the Commission's Siting Committee, stating that "the basic principals of the policy are sound. The policy requires that the lowest quality cooling water reasonably available from both a technical and economic standpoint should be utilized as the source water for any evaporative cooling process . . ." (SWRCB 2002).

CEC IEPR Water Policy

The CEC has recently formally adopted policy related to water use by power plants in the State in the 2003 Integrated Energy Policy Report (CEC 2003) that recognizes the importance of the need to conserve the State's water supply. Clean fresh water is an increasingly critical resource in California. California's burgeoning population, expected to grow from 35.5 million in 2003 to 47.5 million in 2020, combined with businesses and industry, will continue to use increasing quantities of fresh water at rates that cannot be sustained. Imbalances in available fresh water supply results in "average year" shortages projected in every region except parts of the San Francisco Bay area and the North Coast. Energy facilities are among the state's many water users and have the potential to affect fresh water supply and water quality.

Since 1996, an increasing number of new power plants have been sited in areas with limited fresh water supplies. As a result, use of fresh water for power plant cooling is increasing. Although water use for power plant cooling is relatively small on a statewide basis, it can cause significant impacts to local water supplies.

Degraded surface and groundwater can be reused for power plant cooling. When sufficient quantities are available, reclaimed water is a commercially viable cooling medium. Of the 8,409 MW of new cogeneration or combined cycle generated capacity permitted by the Energy Commission and brought on line in California between 1996 and September 2002, more than 1,580 MW or 19 percent is cooled using recycled water. Alternative cooling options, such as dry cooling, are also available and commercially viable, and can reduce or eliminate the need for fresh water. Two projects using dry or air cooling became operational in 1996 and 2001. A third project using dry cooling in San Diego County has been permitted by the Energy Commission.

Water quality impacts to surface water bodies, groundwater and land from waste water discharges are being increasingly controlled through use of technologies such as zero liquid discharge systems in order to meet the state's water quality standards. Of the 8,409 MW of new cogeneration or combined-cycle generating capacity permitted by the Energy Commission and brought on line in California between 1996 and September 2002; 16 percent used zero liquid discharge. More than 35 percent of the projects now under licensing review or under construction will use this technology.

Water conservation is of paramount importance to the state. Indeed, conserving fresh water and avoiding its wasteful use have long been part of the State's water policy, as reflected in the State Constitution, Article X, Section 2. Because power plants have the potential to use substantial amounts of water for evaporative cooling, the Energy Commission has the responsibility to apply state water policy to minimize the use of fresh water, promote alternative cooling technologies and minimize or avoid degradation of the quality of the state's water resources.

State water policy regarding power plants is specified in Resolution 75-58 adopted by the State Water Resources Control Board (the Board). With respect to using fresh water, the Resolution articulates an underlying policy "to protect beneficial uses of the state's water resources and to keep the consumptive use of freshwater for power plant cooling to that minimally essential for the welfare of the citizens of the state." The policy reflects the state's concerns over discharges from power plant cooling, as well as the conservation of fresh water for cooling purposes.

Specifically, the Board states that it "encourages … power generating utilities and agencies to study the feasibility of using wastewater for power plant cooling" and "encourages the use of wastewater for power plant cooling where it is appropriate." The Board also lists specific "discharge prohibitions" to limit the discharge of blowdown and waste waters from cooling facilities so as to "maintain existing water quality and aquatic environment of the state's water resources."

The Board further states as a matter of principle, "Where the Board has jurisdiction, use of fresh inland waters for power plant cooling will be approved by the Board only when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound."

The Warren-Alquist Act reiterates state water policy in terms of conserving water and using alternative sources of water supply: "It is further the policy of the state and the intent of the Legislature to promote all feasible means of energy and water conservation and all feasible uses of alternative energy and water supply sources”.

As stated in the CEC’s 2003 Integrated Energy Policy Report, the CEC water policy is as follows:

> *Consistent with the Board policy and the Warren-Alquist Act, the Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be “environmentally undesirable” or “economically unsound.” Additionally, as a way to reduce the use of fresh water and to avoid discharges in keeping with the Board’s policy, the Energy Commission will require zero-liquid discharge technologies unless such technologies are shown to be “environmentally undesirable” or “economically unsound.” The Commission interprets “environmentally undesirable” to mean the same as having a “significant adverse environmental impact” and “economically unsound” to mean the same as “economically or otherwise infeasible.”*

Colorado River Groundwater Use and Consistency With State Water Policy

The Applicant has proposed in AFC Table 7.13-9 that the “Project will conform with use of low quality groundwater, and use of brine concentrator for maximum recycling, and offset of water use through water conservation program”. AFC Table 7.13-5 further states that “Mesa groundwater is of marginal brackish quality satisfying State policy for use of inland waters”.

This SWRCB policy recommends that power plant cooling water should come from, in order of priority: wastewater being discharged to the ocean, ocean water, brackish water from natural sources or irrigation return flow, inland waste waters of low total dissolved solids, and other inland waters. This policy also addresses cooling water discharge prohibitions. The policy contains the following definitions, among others (SWRCB Policy 75-58):

1. Inland Water – all waters within the territorial limits of California exclusive of the waters of the Pacific Ocean outside of enclosed bays, estuaries, and coastal lagoons.

2. Fresh Inland Waters – those inland waters which are suitable for use as a source of domestic, municipal, or agricultural water supply and which provide habitat for fish and wildlife.

3. Salt Sinks – areas designated by the Regional Water Quality Control Boards to receive saline waste discharges.

4. Brackish Waters – includes all waters with a salinity range of 1,000 to 30,000 mg/l and a chloride concentration range of 250 to 12,000 mg/l. The application of the term "brackish" to a water is not intended to imply that such water is no longer suitable for industrial or agricultural purposes.

The groundwater beneath the Palo Verde Mesa has a TDS marginally (i.e., 1010-1050 ppm TDS) greater than the 1000 ppm TDS categorized as "brackish" by the policy. The Applicant has argued that the policy recommends this groundwater be used to cool power plants. The 1000 ppm TDS level is equivalent to the State's secondary maximum Contaminant Level (MCL) for drinking water, exceedance of which does not render such water unfit for use as drinking water or any other beneficial use. Secondary MCLs are aesthetics-based, water quality standards that are applicable to public water systems, and are set to protect odor, taste, and appearance. They do not prevent this water from being used as a source of drinking water or to satisfy other beneficial uses, which it does for those users dependent on it and who have no other source of water.

Policy 75-58 is somewhat dated and subject to interpretation in this regard, since this groundwater is used for, and meets the beneficial use requirements for the definition for "Fresh Inland Waters" with regard to domestic, municipal, and agricultural water supply beneficial uses. The fact is, this groundwater aquifer is a "source of drinking water" under the more recent SWRCB Policy 88-63, the "Sources of Drinking Water" policy for the State, and is widely used in the area for just that purpose. As discussed under **Laws, Ordinances, Standards, and Regulations (LORS)** in this PSA section, this groundwater is of substantially higher quality and greatly exceeds any of the requirements of Policy 88-63 that would qualify it to be exempted as a source of drinking water, which include:

1. Surface and ground waters where:
   a. The total dissolved solids (TDS) exceed 3,000 mg/L (5,000 uS/cm, electrical conductivity) and it is not reasonably expected by Regional Boards to supply a public water system, or
   b. There is contamination, either by natural processes or by human activity (unrelated to the specific pollution incident), that cannot reasonably be treated for domestic use using either Best Management Practices or best economically achievable treatment practices, or
   c. The water source does not provide sufficient water to supply a single well capable of producing an average, sustained yield of 200 gallons per day.
2. Surface Waters Where:
   a. The water is in systems designed or modified to collect or treat municipal or industrial wastewaters, process waters, mining wastewaters, or storm water runoff, provided that the discharge from such systems is monitored to assure compliance with all relevant water quality objectives as required by the Regional Boards; or,
   b. The water is in systems designed or modified for the primary purpose of conveying or holding agricultural drainage waters, provided that the discharge from such systems is monitored to assure compliance with all relevant water quality objectives as required by the Regional Boards.

3. Ground water where:
    a. The aquifer is regulated as a geothermal energy producing source or has been exempted administratively pursuant to 40 Code of Federal Regulations, Section 146.4 for the purpose of underground injection of fluids associated with the production of hydrocarbon or geothermal energy, provided that these fluids do not constitute a hazardous waste under 40 CFR, Section 261.3.

Importantly, and as discussed in staff's Water Supply and Cooling Option Study (Appendix A), the use of this groundwater would clearly be inconsistent with State water policy that requires the lowest quality cooling water reasonably available from both a technical and economic standpoint to be used as the source water for any evaporative cooling process. There is adequate much lower quality agricultural drain water available in close proximity to the project location. However, the Colorado River water supply-related impacts associated with the use of agricultural drain water are similar to those of Colorado River groundwater.

It is staff's position that neither the California Constitution nor the State water policies derived from it, including the CEC 2003 IEPR water policy, support the use of Colorado River groundwater for power plant cooling. The water the project proposes to use is a source of fresh drinking water on the Mesa, and is used for most if not all beneficial uses of fresh water since it is the only water available.

Cumulative Impacts to the State's Colorado River Water Supply

Staff is in agreement with the PVID, the CRB, and the USBR that the BEP II project is intending to use groundwater underlying the PVID that will be replaced with Colorado River water. Use of this groundwater constitutes use of Colorado River water by the project in accordance with the definition of Colorado River water contained in the Law of the River. This determination is also consistent with groundwater-surface water hydrology technical data, and the USBR/USGS accounting surface representing the Colorado River aquifer.

The WCOP approach is not capable of eliminating the project's use of water that will be replaced by Colorado River water. The unmitigated consumptive use of Colorado River water, particularly during this time when the State must reduce its use of this source of water by approximately 800,000 acre-feet per year is considered to be a contribution to a significant cumulative impact affecting the State's Colorado River water supply and the users of this resource.

Status of the Colorado River

The Colorado River has an average annual flow greater that 17.5 mafy. More water is exported from the Colorado River basin than from any other river in the United States, and provides municipal and industrial water for a population exceeding 24 million in the seven Colorado River Basin states, which include Arizona, California, Colorado, Nevada, New Mexico, Utah and Wyoming. In addition, it provides irrigation for approximately 2 million acres of agriculture lands (Anderson 2002).

The Colorado River Compact of 1922 apportioned 7.5 mafy each to both the Upper and Lower Colorado River basin, with an additional 1 mafy allowed for the Lower Basin. Mexico is guaranteed 1.5 mafy by the Mexican Water Treaty of 1944, along with a pro rata reduction during shortage periods (Pontious 1997). California was apportioned 4.4 mafy, but has been using approximately 5.2 mafy over the past 20 years, about 800,000 afy more than its allocation (Anderson 2002). The Colorado River supplies approximately 14 percent of the water used for agricultural, industrial, commercial business, and residential purposes in California, and represents over 60 percent of Southern California's water supply (LOA 1997). It was for the first time in 1990 when Arizona, California, and Nevada completely consumed the total Lower Basin's 7.5 mafy allocation (UA 1997).

Interim Surplus Guidelines and the Quantification Settlement Agreement

Interim Surplus Guidelines were developed by the Secretary of the Interior to address this overuse of Colorado River water by California. These guidelines allow for a 15-year period during which California must reduce its water use by 800,000 afy to its allotted 4.4 mafy by 2016. The guidelines are designed to allow the State to meet its municipal and industrial needs, while protecting other states from potential drought-related impacts during the 15-year reduction period by reducing the State's municipal and industrial water demands that can be satisfied by surpluses as reservoirs are depleted during drought. The Secretary of the Interior determines how much water is available during each calendar year, and declares either a normal, surplus, or shortage water year (Anderson 2002).

The state's earlier use of the surplus was not considered to be an issue because the six other states entitled to Colorado River water were not using their full allotments. This is still the case for the Upper Basin states of New Mexico, Colorado, Wyoming and Utah. However, Arizona and Nevada are currently using their full entitlements. As a result, the other states requested that the federal government reduce California's water use to ensure the surplus does not legally become considered a permanent part of any state's entitlement (CVWD 2003).). California has become more dependent than ever on surplus Colorado River water, and drew more than 5.3 mafy of water from the Colorado River In 2002 (Stapleton 2003).

The Interim Surplus Guidelines require that California determine how its 4.4 mafy share of Colorado River water will be divided among the State's users of this resource. California must reduce its use of Colorado River water by 280,000 acre-feet per year by January 1, 2006 or by another 380,000 acre-feet by January 1, 2011, or the guidelines will be suspended until the reduction goals have been met. The guidelines are set to expire on December 31, 2016.

The process by which California's is to accomplish this reduction is referred to as the "Quantification Settlement Agreement" (QSA), which is an integral part of the implementation of California's Colorado River Water Use Plan (4.4 Plan) to reduce it's Colorado River water use to 4.4 mafy. The QSA is a package of long-term Colorado River water supply agreements between four California water agencies that include Metropolitan Water District of Southern California, Imperial Irrigation District, San Diego County Water Authority, and the Coachella Valley Water District. Under the QSA, up to 36 million acre-feet of water would voluntarily shift from agricultural use to urban use, thereby reducing California's over-reliance on the Colorado River for urban uses (Stapleton 2003).

The Secretary of the Interior gave California until December 31, 2002 to execute the QSA, a deadline that the State did not meet due to internal disagreement between the water users subject to the 4.4 Plan. The QSA was not signed, and on January 1, 2003 the Secretary of the Interior immediately reduced California's Colorado River allotment to 4.4 mafy, with the State not allowed to use surplus water in 2003 under the Interim Surplus Guidelines until the 4.4 Plan/QSA issue is resolved. The amount of water California could withdraw was reduced by 650,000 acre-feet per year (212 billion gallons/year), or enough water for approximately 4.8 million people (Bulkley 2003). Due to the priority system of California's Colorado River water rights based on junior and senior rights, the Metropolitan Water District suffered all of the reduction (Stapleton 2003).

The swift and aggressive action by the Secretary of the Interior to abruptly terminate the excessive use of Colorado River water by California in the absence of a valid QSA, and the conflicts the shortage of Colorado River water has caused within the State are indicative of both the severity and the immediacy of the problems related to balancing the increasing demand with the decreasing supply of Colorado River water. It is also a vision of the relatively near-term future during the intervening years over which California must permanently reduce it dependence on Colorado River surplus flows by 2016. The QSA has since been signed by all parties, although it is still a subject of contention among California's Colorado River water users, and may yet be challenged in the courts.

The Colorado River's status at this time is best described by the CRB's recent letter (CRB 2003):

> "The current status of the Colorado River water supply is a bleak one. Generally, the Colorado River basin is experiencing a fourth year of drought and little, if any, surplus water is anticipated in the near future. For example, the Coachella Valley Water District's (Coachella) supply was reduced on April 28th of this year from 338,820 acre-feet to 238,500 acre-feet for this calendar year (Enclosure 1). The Metropolitan Water District of Southern California (Metropolitan) requested 1,250,000 acre-feet for this calendar year. Metropolitan's supply was reduced to 713,500 acre-feet on January 1st and to 592,500 acre-feet on April 28th for this calendar year (Enclosure 2)."
>
> "Coachella has had to execute leases with farmers in the Palo Verde Valley, served by the Palo Verde Irrigation District, this year for a six-month period, beginning June 20th, in return for compensation of $750 per acre (Enclosure 4)."
>
> Note: The enclosures referenced in the excerpts above refer to information contained in the CRB's submittal.

While California's Colorado River water supply can be affected by drought at any time and most likely will be at some time, it will definitely and predictably be affected during the period from the present to 2016 when demand for water in the State can be expected to increase, and California will be reducing its use of surplus Colorado River water in order to live within its allocation of 4.4 million acre-feet per year.

The Law of the River has evolved over time in response to the many disputes over rights to the use of the Colorado River, and the QSA represents another step in that evolution. The nearly year-long dispute surrounding its signing is an indicator of not only how vital a resource it is to those who depend on it, but is also as a reflection of how severely it has been impacted in its ability to meet the increasing needs of those same dependents. This is particularly true in the case of California during this time of forced reductions in Colorado River water use over the next 14 years, where any unnecessary use consuming Colorado River water, such as that proposed by the BEP II project, would be considered unreasonable, and a contribution to an existing and increasing significant cumulative impact.

Considering the increasing pressures on fresh inland water resources in California, particularly in the case of the Colorado River, the State has adopted a number of State regulations and water policies promoting the conservation of this valued resource, all in accordance with Article X, Section 2, of the State Constitution. This increasing pressure is reflected in the direction of State regulation and water policies, including those of the CEC, to avoid both the unnecessary use of freshwater and the associated cumulative impacts to the State's water supply. This is particularly true where degraded/recycled water sources are available for non-potable uses where feasible, and where newer and more progressive water conserving alternative cooling technologies are employed.

Staff has analyzed the feasibility of using other sources of water and cooling technology for the project, and determined the use of significant amounts of water for cooling to be unnecessary. Staff concludes that while degraded/recycled water would not mitigate all Colorado River water use-related significant cumulative impacts, use of alternative cooling technology would (see Staff Proposed Mitigation and Appendix A). Under these circumstances, the use of fresh water for evaporative cooling represents an unreasonable method of use that will result in a waste of water. This unreasonable use of water is a contribution by the BEP II project to a significant cumulative impact to California's Colorado River water resource and its users.

Cumulative Impacts to the PVID

Due to the BEP II project's location within the PVID service area and the interrelated hydrology of Colorado River surface water and groundwater within the PVID, evaluation of cumulative impacts to the PVID water supply and those dependent on this source of water is necessary. As previously discussed, if Colorado River groundwater is used to cool BEP II, direct impacts to the PVID water supply have been established and must be mitigated. The BEP II project's direct impact resulting from the pumping and consuming of Colorado River ground water is not the only such impact within the PVID.

There are other wells within the PVID service area that also pump Colorado River groundwater, an example being the BEP I wells. When these other wells are considered along with those of BEP II, together they represent a cumulative impact to the PVID water supply and its users.

Groundwater - Cumulative Well Interference Impacts

Cumulative well interference impacts have been evaluated in terms of the effect of the proposed BEP II and BEP I, which is operational, but not operating at this time. The water supply demand of the two projects and the well interference of the two projects is additive and is, therefore, roughly double the impact of BEP II alone.

Applicant's Analysis of Cumulative Well Interference Impacts

The Applicant provided an analysis in the AFC that evaluates cumulative well interference impacts that would be caused by groundwater pumping for BEP II and BEP I combined (Soil and Water Resources Table 12). However, the Applicant based this analysis on the results of BEP I's first aquifer test for project well PW-2 (BEP I 2002). The Applicant's analysis included an evaluation of the impact of pumping for BEP II and BEP I at average long-term pumping rates and short-term maximum pumping 4-month summer-peak demand rates.

Soil and Water Resources Table 12
Results of Applicant's Well Interference Analysis
of Combined Pumping for BEP II and BEP (1)

	1000 feet	2000 feet	Sun World Well (4140 feet) (2)	1 mile (5280 feet)
Long-Term Average Pumping Rate (40 years) Drawdown (feet)	5.9	5	4.2	3.8
Short-Term Maximum Pumping Rate (4 months) Drawdown (feet)	4.2	3.4	1.8	1.4

(1) Drawdown data for BEP II plus BEP I impacts: AFC, Section 7.13.2.3 and Figure
(2) Sun World Well – Identified by Applicant as nearest known well.

Using a significance threshold of 5 feet drawdown on existing wells, the Applicant concluded that well interference caused by BEP II and BEP I combined would have no significant adverse impact on nearby existing wells under long-term pumping conditions or short-term maximum pumping conditions.

Staff Analysis of Cumulative Well Interference Impacts

Groundwater pumping for BEP II, in addition to pumping for BEP I, will double new well interference impacts to the Palo Verde Mesa. Particular attention should be given to the effect of cumulative well interference impacts on pump elevations and operation in nearby existing wells. Even brief periods of dewatering causes damage to water well pumps.

The significance criteria for pump damage caused by well interference would be the same for evaluating cumulative impacts as it would for direct impacts. Well interference from project pumping that exceeded 5 feet under average long-term pumping conditions or short-term maximum pumping conditions would be likely to damage pumps in existing wells near the project if these pumps have been configured considering industry standards (Driscoll 1986).

For this preliminary staff assessment, staff evaluated the potential cumulative well interference impacts that would be caused by groundwater pumping for BEP II and BEP I combined, based on the aquifer parameters calculated by BEP I from the data from the production well aquifer field tests. Again, given the proximity of BEP I to the BEP II site, it is reasonable to assume that aquifer parameters are essentially the same at both sites. For the cumulative analysis staff considered the location of both the existing BEP I well sites and the proposed BEP II well sites. The distance from both sets of wells are listed in Soil and Water Resources Table 13, below.

Soil and Water Resources Table 13
Distance From BEP II and BEP I Production Wells
and Nearest Known Existing Well

Production Well	Approximate Distance from Thermal King Shop Well (feet)
BEP II PW-2	2800 (1)
BEP II PW-1	2575 (1)
BEP I PW-2	4002 (2)
BEP I PW-1	3315 (2)

(1) Based on manual map measurements using BEP II response to Round 3 Data Request 64, Figure 64-1.

(2) Based on distance given in BEP I reports, “Results of the Aquifer Test on Blythe Production Well PW-1” (6/2003) and “Results of the Aquifer Retest on Blythe Production Well PW-2” (5/2003)

Using the average of the aquifer parameters calculated by BEP I and a simple Theis equation method, staff had calculated the well interference impacts that would be caused by BEP II and BEP I pumping (1) for average long-term (40 years) drawdown and (2) for the maximum pumping rate drawdown (Soil and Water Resources Table 14).

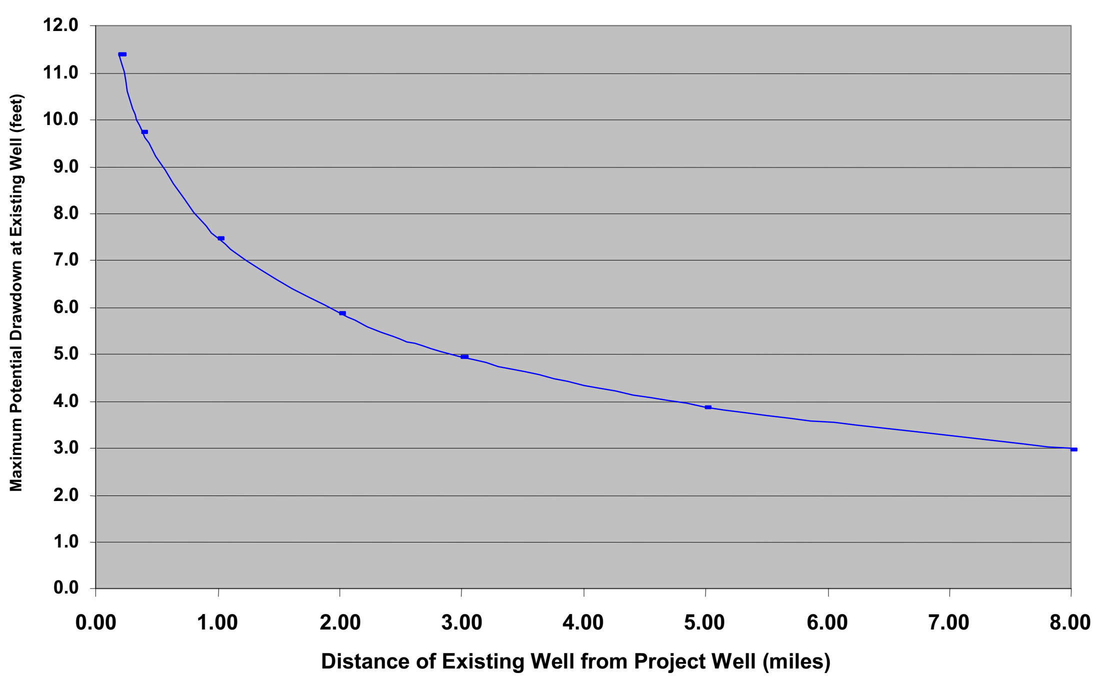
Soil and Water Resources Table 14
Results of Staff Well Interference Analysis
Combined Well Interference Impact of BEP II and BEP I Pumping (1)

	1000 feet	2000 feet	Thermal King Well (3170 feet) (2)	1 mile	2 miles	3 miles	8 miles
Long-Term Average Pumping Rate (40 years) Drawdown (feet)	9.2	8.1	7.3	6.5	5.3	4.6	3.0
Short-Term Maximum Pumping Rate (4 months) Drawdown (feet)	11.4	9.8	8.7	7.5	5.9	5.0	3.0

(1) BEP II - Average Pumping Rate = 2,050 gpm (3300 acre fee/year); maximum pumping rate for any four-month period = 2,898 gpm; BEP I - Average Pumping Rate = 2,040 gpm (3290 acre feet/year); maximum pumping rate for any four-month period = 2,882 gpm

(2) Thermal King Shop well – Identified by staff as nearest known existing well, located on Hobsonway, southwest of proposed project wells. The Thermal King well is about 3170 feet from the combined BEP I-BEP II well field.

Soil and Water Resources Figure 4
Maximum Cumulative Well Interference
from BEP II and BEP I



Based on a significance criteria for well interference of 5 feet drawdown for pump damage, the BEP II project pumping would cause significant impacts to wells within about 3 miles from the project site on the Palo Verde Mesa. However, water levels in wells located in the Palo Verde Valley would probably not be affected because groundwater recharge from PVID irrigation with Colorado River water would maintain groundwater levels within the valley.

ENVIRONMENTAL JUSTICE

Based on the Soil and Water Resources analysis, staff concludes at this time that the proposed project would not cause disproportionate significant impacts to any particular population or population subgroup. The significant direct and cumulative impacts to the PVID water supply and its water users, the significant cumulative impact to the State's Colorado River water supply and its users, and any impacts resulting from well interference due the project's use of groundwater that is replaced with Colorado River water appear to be evenly distributed over the general population in the area. Of particular interest were possible impacts to the community of Mesa Verde, and no disproportionate impacts to this community water supply were determined.

Please refer to the **Socioeconomic Section** for an analysis of potential environmental justice implications of the WCOP on the local agricultural community.

MITIGATION

APPLICANT PROPOSED MITIGATION

Soils

The Applicant proposes to incorporate standard BMPs into the project design for construction and operation to mitigate erosion and sedimentation impacts.

Groundwater

The Applicant has not provided a draft Storm Water Pollution Prevention Plan (SWPPP) for industrial operation at the BEP II facility. However, the Applicant has indicated that drains and sumps will be utilized for spill prevention and control, and that storm water runoff from process areas will be routed through a oil-water separator and discharged to the evaporation ponds (BEP II 2002a, Data Request 68). These measures are intended to minimize the potential for ground water contamination.

Applicant's Well Interference Mitigation Measures

The Applicant has proposed an agreement to accept the Conditions of Certification Soil and Water 6 and 7 that were required for BEP I, which are related to well interference impacts (BEP II 2003, Response to Data Request 199). The Applicant stated their support for conditions that included on-site aquifer testing on project production wells, calculation of well interference from the aquifer test results and reimbursement of existing well owners for impacts, which staff notes would include Soil and Water 5, as well as Soil and Water 6 and 7.

Groundwater Quality Mitigation

The Applicant has recommended the adoption of the BEP I Condition of Certification Soil and Water 10, which requires annual analyses of groundwater samples from on-site wells and reassessment of treatment requirements if significant changes in groundwater quality occur.

Surface Hydrology

All non-process storm water runoff will be routed to the retention basin where it will percolate into the subsurface.

Storm Water

The Applicant has submitted a draft construction SWPPP that generally addresses BMPs that may be used at BEP II. More site specific BMPs that will reduce erosion and sedimentation impacts and their possible impacts to surface water quality will be required in the project design for construction and operation. Measures established within the operational SWPPP regarding spill control would also protect surface water resources. Areas where there is a possibility for runoff to encounter contaminants will be collected in drains and sumps. The runoff from these portions of the site will be routed through an oil/water separator and discharged to the evaporation ponds, eliminating this potential source of polluted runoff. The Applicant will be required to meet general storm water requirements of the NPDES permit.

Wastewater Disposal

The Applicant has submitted a Waste Discharge Permit Application that generally addresses wastewater disposal. Wastewater from the proposed BEP II facility will be discharged to the project's evaporation ponds as concentrated brine. The evaporation ponds are designed with double containment and leak detection to limit the potential for impacts to soil and groundwater resources.

STAFF PROPOSED MITIGATION

Soils

BEP II Site and Linears

Staff recommends that the Applicant be required to meet general storm water requirements of the NPDES permit. As required by Colorado River Basin RWQCB Order 99-08-DWQ (Storm water during construction) and Order 5-00-175 (discharge of short duration or low threat), a Storm Water Pollution Prevention Plan (SWPPP) would be implemented to minimize erosion from construction and operation activities. The Applicant must develop and implement a site specific Drainage, Erosion and Sedimentation Control Plan for the entire project (including ancillary facilities) that addresses standard erosion runoff and sedimentation impacts for construction, post-construction, and operational phases. The Applicant should provide a complete, site-specific Erosion and Sedimentation Control Plan, or a complete SWPPP that includes the BEP I and II site and addresses all staff's and other agencies' concerns. The

Applicant must revise the draft plans to provide the following amendments and additions to the plans for the entire proposed BEP II project. The plans should include:

- The topographic features of the proposed project including areas involving all proposed pipeline construction, laydown (staging) area, transmission upgrades, and stockpile location(s). The mapping scale shall be at least 1”= 100’ (1”=50’ recommended). Include not less than 1000 feet of the surrounding area of the sites (topography and existing features) on the drawings.
- A construction schedule that addresses all BMP installation, maintenance and removal sequences of events from initial site mobilization to final stabilization (i.e. vegetation/asphalt) and plant operation.
- Proposed contours shall be shown tying in with existing ones. All proposed utilities including storm water facilities should be shown on the plan drawings. All erosion and sedimentation control facilities should be shown on the drawings. The drawings should contain a complete mapping symbols legend that identifies all existing and proposed features including the soil boundary and a limit of construction. The limit of construction boundary should include the project facility, pipeline areas, stockpile areas, laydown areas, and any off-site staging areas. The limit of construction boundaries ensures all work is confined to the proposed BEP II project in order to protect all surrounding areas not involved in construction or operation of the proposed project.
- Silt fencing and sandbags shall be used to trap sediment, and not as runoff conveyance facilities. Earthen berms or channels can be substituted to intercept sediment-laden runoff and direct it into the sediment retention basin/trap. A sediment trap should be used for drainage areas less than five acres and a sediment basin should be used for drainage areas greater than five acres.
- All excavated material shall be kept away from active flows. Site specific BMPs shall be included in narrative and drawing portions of the erosion and sediment control plan. The soil shall be covered via a liner or anchored mulch. Areas disturbed during construction shall be stabilized via permanent vegetation upon completion of the process.
- Appropriate BMPs shall be employed for all project-related construction including, but not limited, to access roads, directional drilling / tunneling, linear facilities, and any off-site staging areas. All BMPs shall be shown on legible drawings of appropriate scale.
- Revegetated or landscaped areas and a description of revegetation procedures shall be included on the drawings.
- Soil stockpile management BMPs shall be included for water and wind erosion control.
- Maintenance and monitoring protocol for erosion/storm water control shall be clearly described.

Water Conservation Offset Plan

Staff has determined the WCOP is inadequate mitigation for the projects significant impacts. Staff found the WCOP to be deficient with regard to how the plan would be implemented, managed, monitored, verified, and reported to ensure the fallowing program does not lead to significant erosion impacts or degradation of soil quality and productivity. The land management measures included in the WCOP were determined to not be consistent with applicable NRCS standards, and the plan was not reviewed by either the NRCS or the PVID.

Well Interference Mitigation Measures

Because of significant impacts related to the proposed project, staff is recommending an alternative project design that will avoid significant impacts, including those related to well interference. Therefore, staff is not proposing mitigation for impacts associated with the proposed project.

For the proposed project, staff would recommend that mitigation for well interference impacts be based on analysis of the aquifer test data from BEP I production wells, which are located adjacent to the proposed BEP II project site. Given the proximity of the BEP I wells to the BEP II proposed well sites, there would be no need for additional testing. Two separate mitigation measures for well interference impacts would be necessary. Well owners of large-capacity wells would be mitigated for increased energy costs of pumping water, well owners of small-capacity wells would be mitigated for the cost for lowering pump bowls if needed. The project owner would need to notify all property owners on the Palo Verde Mesa that would experience a cumulative impact of 5 feet or more of drawdown from combined pumping from BEP II and BEP I.

Groundwater Quality Mitigation

Pending the Applicant’s submission of the full August 2002 water quality analyses for the BEP I production wells, staff will provide its any necessary recommendations to address the potential for adverse impacts to groundwater quality in Final Staff Assessment.

Surface Hydrology

As proposed, all runoff originating on the BEP II site and land upgradient of the BEP II site will be routed to the project’s retention basin where it will percolate into the subsurface. Staff needs the Applicant’s calculations that demonstrate the proposed retention basin can contain the runoff produced by a 100-year event and meet the City of Blythe’s freeboard requirements.

The proposed retention basin design does not include an outlet structure or an emergency spillway to route overflows away from the retention basin. Runoff from an extreme storm event could overtop the retention basin, leading to a failure of the containment berm and potentially cause flooding and erosion impacts downstream of the BEP II site. Staff recommends that the Applicant revise the retention basin design to include an emergency spillway or outlet structure to safely route potential overflows away from the containment berm. Staff will need a revised Storm Drainage Calculations package and a revised retention basin design in order to complete the FSA.

Storm Water

BEP II must comply with the general NPDES requirements that regulate storm water discharges. These requirements regulate storm water by establishing effluent limitations and monitoring and reporting requirements for construction activities storm water, low-threat or short duration discharge, and the industrial activities (operational) dictated by the storm water general permit. The draft SWPPP should be revised to be site specific and comply with the guidelines provided in RWQCB's Water Quality Order 99-08-DWQ and 97-03-DWQ. The BEP II should supply all information required by the Regional Water Quality Control Board (RWQCB) and Energy Commission staff to determine compliance with the NPDES requirements for storm water discharge. This includes the required construction and operational SWPPPs. The Applicant shall be responsible for all monitoring and reporting guidelines and other provisions included in the general storm water permits. This process also requires the submittal of a SWPPP, and implementation of the approved plan will mitigate any storm water impacts from the project.

Process and Sanitary Wastewater

Process Wastewater

The proposed evaporation pond design includes a double contained pond liner system with leak detection to limit the potential for impacts to soil and groundwater resources. However, the design specifications for the proposed evaporation ponds appear to be incorrect in the Waste Discharge Permit Application submitted by the Applicant to the RWQCB to obtain Waste Discharge Requirements. Staff finds it necessary for the Applicant to submit a revised Waste Discharge Permit Application to the RWQCB that includes accurate calculation of the capacity of the proposed evaporation ponds.

For staff to complete the analysis of the project, the Applicant will need to submit copies of the final draft Waste Discharge Requirements for wastewater discharge to the evaporation at least 30 days prior release of the FSA so that it can be determined that the proposed project design and operational plan will comply with LORS. The Applicant has proposed no back-up for the brine concentrator system. Staff recommends the project be operated in a manner consistent with the RWQCB WDRs for the evaporation ponds, and that the required freeboard not be exceeded. These proposed mitigation measures and corresponding Conditions of Certification would ensure that soil and groundwater water quality is not impacted by the process wastewater activities.

Sanitary Septic System

The on-site septic system and drainfield should be designed according to applicable city and county laws in order to prevent any significant impacts to water quality. The Energy Commission CPM must receive comment from the City of Blythe's on approval of the plans. CPM approval is need prior to the start of septic system construction activities.

Water Supply – Heat and Water Balances, and Project Design

Information currently available on the project is not technically consistent as it relates to water balances, heat balances and project design. Staff needs accurate and consistent heat and water balances to allow the projects water requirements to complete analysis of the project. .

Use of Colorado River Water

The Applicant's proposed use of an evaporative cooling system will result in approximately 3300 acre-feet per year of Colorado River groundwater being consumed. Based on staff analysis of readily available, practicable, and currently in use by the industry in the State alternative cooling technologies developed in Appendix A, staff has determined the use of this water in an evaporative cooling system to be unnecessary. In addition, staff has determined this unreasonable use of water to be a contribution to a significant cumulative impact to the State's Colorado River water supply, and to the users dependent on it. The Applicant recognizes no significant direct impact to the PVID and its water users, or a potentially significant cumulative impact to the Colorado River water supply or its users resulting from the use of Colorado River groundwater. Consequently, the Applicant has proposed no mitigation measures to either eliminate or mitigate these impacts to less than significant as required by CEQA. Staff can not recommend approval of a project having unmitigated significant or potentially significant impacts.

Possible Alternatives to the Proposed Water Supply

In order to consider options for mitigating the significant direct and potentially significant cumulative impacts to other users of this resource, Staff analyzed the following water supply and cooling alternatives in detail in comparison to the proposed project:

The Proposed Project – Use of Colorado River Groundwater with Wet Cooling;

Alternative 1 – Reclaimed Water from City of Blythe's WWTP with Wet Cooling;

Alternative 2 – Irrigation Return Water from PVID with Wet Cooling;

Alternative 3 –Irrigation Return Water from PVID with Hybrid Cooling (1/3 Wet/2/3 Dry);

Alternative 4 – Dry Cooling.

From a water conservation standpoint and to achieve conformity with State regulations and policies, including that of the CEC, Dry Cooling would accomplish the highest conservation of Colorado River water pumped as groundwater, reducing average annual water use from 3,262 AFY to about 40 AFY. No new water supply infrastructure (wells, pumps or off-site pipelines) would be needed, as the minimal 40 AFY needed to support Dry Cooling could be made available using the existing BEP I infrastructure. Staff believes conservation of water supplies throughout California, and specifically the Colorado River water supply in this case, is imperative based on the findings made in this Staff Analysis and the need to preserve the highest quality water for the highest beneficial use consistent with state regulations and policies, including the IEPR water policy of the CEC. Staff finds Dry Cooling to be the preferred cooling alternative.

Dry cooling will provide either the CEQA-required “roughly proportional” mitigation for, or elimination of, significant direct and cumulative impacts determined in this Staff Assessment to result from the proposed project’s use of Colorado River groundwater. These significant and potentially significant impacts include:

- Direct significant impact to the PVID water supply and its water users.
- Significant cumulative impact to the State’s Colorado River water supply and its users.
- Potentially significant cumulative impact to the PVID water supply and its users.

Based on the compilation of environmental and engineering measures developed in Appendix A and presented in Soil and Water Resources Appendix Table 9, staff finds Alternative 4 – Dry Cooling (subject to the environmental analysis currently ongoing) to be fully consistent at this time with the requirements of CEQA with regard to feasibility, which includes consideration of economic, environmental, legal, social, and technological factors. When accounting for financial elements other than lost power effects from hybrid or dry cooling, all alternatives are equivalent in cost to the proposed project.

After accounting for lost power generation, the incremental effect on the cost of power production is only about 6/100 to 12/100 of a cent per KWH higher (assuming power values ranging from $30 to $60 per MWH) to implement dry cooling compared to the proposed project. Neither of these increments of cost will significantly affect project economics or the owner’s ability to market power. Dry Cooling would require an additional capital investment of about $12 million over the capital cost of the proposed project. However, the annual BEPII O&M costs for the proposed project using wet cooling are about $800,000 more that those for Dry Cooling, which effectively makes the alternatives comparable in out-of-pocket cost over the life of the project.

Consistency of Alternatives with the California Constitution, Water Code and State Water Policy

Staff has determined that with implementation of the Dry Cooling alternative would conform to reasonable use of water as defined in the State Constitution, Water Code, and State policies, including the 2003 IEPR water policy of the CEC. This Staff Analysis has determined the Dry Cooling alternative to be environmentally desirable and economically sound. The complete Water Supply and Cooling Options analysis is contained in Appendix A, which is incorporated into this Soil and Water Resources section of the PSA by reference.

COMPLIANCE WITH LORS

The analysis of compliance with LORS was conducted in a manner consistent with the requirements of CEQA, the Warren-Alquist Act, and the CEC siting regulations.

STATE WATER POLICY AND LORS

See **Statement of Counsel** under **Cumulative Impacts**. It is staff’s opinion the proposed project and its consumptive use of 3300 acre-feet per year of Colorado River groundwater does not conform to California Constitution Article 10, Section 10, or any of the State water policies, including that of the CEC, or California Water Code regulations that are derived from Article 10.

COLORADO RIVER – LAW OF THE RIVER AND THE USBR WATERMASTER AUTHORITY

Definitively understanding the USBR's official regulatory position with regard to the issue of the use of groundwater that will be replaced with mainstream Colorado River water has been challenging for staff. As discussed in some detail below, staff finds such an understanding must be considered an ongoing effort that is not likely to be achieved for the purpose of this Staff Assessment. This circumstance has come about due to the vagueness and inconsistency displayed in the many letters the USBR has provided to various agencies, including the CEC, as they relate to the CEC licensing process. Staff offers this interpretation of the USBR's regulatory position for consideration.

The USBR Position

Staff has made a good faith attempt to sort out the issues related to the project's use of groundwater that will be replaced with Colorado River water, a task that required a reasonably detailed review of the USBR's position over time on this matter. In previous letters (USBR 2000, 2000a, 2001, 2002), the USBR took the position that while they did have jurisdiction over this water, and while they had a legal responsibility to account for it and regulate its use, they were not currently doing so in a general manner, although they intended to do so in the future. That position is fundamentally unchanged for the general case, although the USBR appears to have taken somewhat greater interest in the existing BEP I and proposed BEP II power plants on the Palo Verde Mesa.

In order to better understand the current regulatory situation, staff has reviewed the USBR's position as stated in their letters on this issue in order that the most recent USBR letter (USBR 2003), discussed later, could be better understood. The following statements are contained in the various USBR letters, and staff has attempted to understand their intent and application for the purposes of this Preliminary Staff Assessment.

> **USBR Statement 1.** "The Secretary of the interior (Secretary), through Reclamation, is vested with the responsibility for managing the mainstream water of the lower Colorado River pursuant to applicable Federal law. This *watermaster* responsibility is carried out consistent with a collection of documents known as the *Law of the River.* Authorized use of Colorado River water requires an entitlement which, except for Federal reserved rights, includes a contract with the Secretary. Consumptive use of Colorado River water, whether derived from a diversion of surface or groundwater, must be accounted for by Reclamation pursuant to a Supreme Court Decree" (USBR 2000).

USBR Statement 2. "Reclamation's jurisdiction over water pumped from wells, such as proposed under this project, only applies if that water will be replaced by Colorado River water" (USBR 2000).

USBR Statement 3. "In summary, we do not have jurisdiction over the permitting and establishment of wells along the lower Colorado River in the states of Arizona, California, or Nevada. However, an entitlement consistent with the existing *Law of the River* is required for any water pumped from wells that will be replaced by Colorado River water" (USBR 2000).

USBR Statement 4. "It is true that the Bureau of Reclamation has no contract or other permit process for the development of new wells. However, there are some instances, (in Yuma for example), where the Bureau does account for pumped groundwater as part of a surface entitlement" (USBR 2000a).

USBR Statement 5. "The Blythe Energy Project is located within the lower mesa portion of the Palo Verde Mesa, which falls within the Priority 3 boundaries of the Palo Verde Irrigation District. Project wells will develop a cone of depression that will extend into the accounting surface. Therefore, it is our position that this water use would be accounted for as part of PVID's Colorado River entitlement" (USBR 2000a).

USBR Statement 6. "If the energy project goes forward, we encourage the development of a water conservation offset program. If as described, the offset program involves lands solely within PVID's boundaries and does not involve the transfer of any waters outside the District, we would view the offset program as part of PVID's internal decision-making, over which the Bureau asserts no jurisdiction" (USBR 2000a).

USBR Statement 7. "However, notwithstanding the Secretary of the Interior's responsibilities under the Decree, we know of no laws, ordinances, regulations, or standards currently being exercised to control or regulate groundwater pumping or other well users upon the Palo Verde Mesa" (USBR, 2002).

USBR Statement 8. "The Applicant has submitted a voluntary Water Conservation Offset Program (WCOP) (enclosed) that would retire or fallow lands that have been irrigated within the Palo Verde Irrigation District (PVID) on the Mesa and/or within the Palo Verde Valley within the past five years" (USBR 2002).

USBR Statement 9. "The WCOP must be in effect upon commercial operation of the BEP II plant and remain in effect for the life of the power plant" (USBR 2002).

Analysis of USBR Position

Staff finds these particular USBR statements to be inconsistent and somewhat confusing for the purpose of determining compliance with the Law of the River. For example, **USBR Statements 1 and 2** (**USBR 1** and **USBR 2**) appear to establish the USBR's jurisdiction and imply an authority to regulate groundwater that will be replaced with Colorado River water consistent with the Law of the River.

USBR 3 states that while the USBR has no authority over the establishment of wells pumping Colorado River water, it does have jurisdiction and implies an authority to regulate the water obtained from such wells as Colorado River water consistent with the Law of the River.

USBR 4 confirms that even in the absence of an established contract or permit process, the USBR has jurisdiction and has exercised some manner of authority over groundwater replaced with Colorado River water in at least one specific instance (Yuma).

USBR 5 finds that the BEP I project, and staff infers the BEP II project, is within the accounting surface constituting Colorado River water use, is within the PVID Priority 3 water right boundaries, and that this water must be accounted for as part of PVID's Colorado River entitlement.

USBR 6 encourages the project to develop a water conservation offset program, and considers the WCOP as part of PVID's internal decision making process.

USBR 7 states that in the USBR's eyes, there are no LORS currently regulating either groundwater use or users on the Palo Verde Mesa. Staff can only infer this statement to suggest that LORS used in this context excludes the Law of the River and the USBR's jurisdiction and implied authority over groundwater replaced by Colorado River. This jurisdiction and implied authority over that groundwater was earlier established by **USBR 1** through **USBR 3.** However, for reasons unknown, it was apparently considered to be inadequate in the USBR's own opinion, to regulate this groundwater at that particular time.

USBR 8 appears to agree that the WCOP submitted by the Applicant is voluntary, while **USBR 9** requires the WCOP to be in effect at the time of commercial operation and to remain in effect for the life of the project. The statement the WCOP is "voluntary", i.e., an exercise of free will by the BEP II Applicant is inconsistent with the requirement that it "...must be in effect...". Also of concern, the USBR had apparently previously questioned the basis for its own authority, i.e., the Law of the River, to regulate this water in **USBR 6, USBR 7,** and **USBR 8,** and has not established a basis for any new authority to actually require a WCOP.

The "voluntary" nature of the need for an effective WCOP, or other means of achieving authorized use of Colorado water pumped as ground water appears to be further called into question by the latest USBR letter (USBR 2003). The issue of whether authorized use of Colorado River water must be obtained for the BEP I project through a WCOP or other means has been raised by the USBR in a letter to Ron Regan of Blythe Energy LLC from Robert W. Johnson, the Regional Director of the USBR, dated July 18, 2003 (USBR 2003).

USBR Statement 10. "If you plan to obtain the water from wells on the Palo Verde Mesa, it is Reclamation's position that the water from the wells would have to be covered by a Colorado River water entitlement. Our records indicate that the ground water table at the location of the wells that would serve BEP is at the same elevation of the Colorado River in that area, and the wells would pump water that would be replaced with water from the Colorado River" (USBR 2003).

USBR Statement 11. "Absent an acceptable land fallowing offset program, a possible program that would provide an acceptable water supply is the Lower Colorado Water Supply (LCWSP). In phone discussions with representatives of BEP, the possibility of the BEP's [*sic*] obtaining a water supply through the Lower Colorado Water Supply Project (LCWSP) has been discussed. If BEP is interested in pursuing the LCWSP as a source of water for BEP, Reclamation stands ready to work with BEP, the City of Needles, the Colorado River Board of California, and others to enable that to happen" (USBR 2003).

USBR Statement 12. **"**Given the imminent operation of BEP, including use of water at the plant, Reclamation requests that BEP identify its plans for the source of water that will be used at BEP and the legal basis for BEP's right to utilize such water" (USBR 2003).

Based on **USBR 10** and **USBR 11**, one could surmise the USBR no longer considers the WCOP or other means of obtaining authorized use of Colorado River water to be voluntary. However, the USBR states no reason or establishes no new basis or formal procedure, such as a rule or regulation, the project must comply with for authorized use of Colorado River water. Interestingly, in **USBR 12** the USBR only "requests" the BEP I Applicant to identify the source of water to be used and the legal basis for its use; it does not require the BEP I Applicant to do so.

The USBR appears to be exercising authority that it previously apparently found inadequate or not applicable to regulate this water on anything other than a "voluntary" basis. Furthermore, the USBR does not appear to be applying these requirements to other groundwater users either on the Palo Verde Mesa and/or within the PVID, nor does it appear to have established any generally applicable contract or permit process, as discussed in **USBR 4,** to do so. This issue is discussed further below in **Unauthorized Use of Colorado River Water**.

Of interest is the discussion of the LCWSP as a means to obtain authorized use of Colorado River water, which the USBR appears to believe could be a means of providing the BEP II project with water. Staff is currently evaluating the use of the LCWSP by the BEP II as an alternative means of obtaining water for the project (see Soil and Water Resources Appendix A). However, based on staff's review of this program at this time it appears this option is not available to the BEP II because the project is located within the PVID service area boundary.

Unauthorized Use of Colorado River Water

The issue of unauthorized use of Colorado River water has been raised in both the BEP I and in the current BEP II proceedings. Unauthorized use results from Colorado River water derived from either the mainstream or pumped as groundwater, being used in the absence of either water delivery contract with the USBR (Secretary of the Interior) in accordance with Section 5 of the Boulder Canyon Project Act, or those with pre-1928 present perfected rights resulting from the Supreme Court Supplemental Decree of 1979 and a water delivery contract with the Department of Interior (CRB 2003, Enclosure 6).

The issue of unauthorized use of Colorado River water has been an ongoing concern to the State, the CRB, and the Colorado River water rights holders it represents. In a letter to Robert Johnson of the USBR from Gerald Zimmerman of the CRB dated July, 9 2003 (CRB 2003, Enclosure 6), the CRB frames the issue in excerpts from this letter as follows:

> "In this "Era of Limits", as your staff has eloquently outlined at your public workshop, and with the current water supply conditions within the Basin, the water use by valid Section 5 water contract holders is being limited. As a result, it is imperative that unauthorized uses of mainstream water within the Lower Basin be terminated. A review of the record shows that a draft Regulation for Administering Entitlements to Colorado River Water in the Lower Basin was set to be published in the *Federal Register* in November 1991."
>
> "Twelve years has now passed since the original draft Rule was proposed and it appears Reclamation is no further along in terminating these unauthorized uses of Colorado River water through issuance of a rule."
>
> "Without such a rule being in place, entities in California who hold valid Section 5 contracts to use Colorado River water are being required to limit their water use while the unauthorized users are allowed to continue their use."
>
> "This places an extreme hardship on the valid users of Colorado River water while unauthorized users are able to operate in violation of the U.S. Supreme Court decree in Arizona v. California. The legal entitlement holders should not suffer for Reclamation's lack of regulating the unauthorized use of water. To be equitable, such unauthorized use of Colorado River water should not be charged against California's annual apportionment until Reclamation has a rule in place to terminate such users and is enforcing it."

Considering the complexities of the Law of the River, the USBR's stated interpretation of its own authority and responsibilities as watermaster of the Colorado River, and the legal and water resource supply issues for both the State and its Colorado River water rights holders, staff finds that the USBR appears to have jurisdiction over this water, but lacks the authority through an apparently required rule or regulation to regulate its unauthorized use. The USBR has not generally regulated unauthorized use in the past, is not currently generally doing so, and has no apparent rule or regulation based enforceable procedure to do so in a general manner that would apply to all past, current, and future users of this water.
In the absence of information to the contrary, staff finds that unless the USBR or other agency formally exerts legally enforceable authority or clearly demonstrates either an actual or potential violation of applicable and enforceable LORS, and clearly elaborates an unambiguous and legally enforceable procedure for compliance, or a court renders a binding decision, considering the BEP II project to be unique in its proposed use of groundwater that is replaced by Colorado River water on the Palo Verde Mesa, and particularly within the PVID, may be unreasonable and unwarranted. This appears to be the case to the extent the project could be considered to be in compliance with existing and reasonably foreseeable LORS as we understand them at this time, and would be expected to be regulated to the same extent as all other users of this resource both now and in the future.

Unauthorized Use of Colorado River Water Within the PVID Service Area

As discussed previously under **Environmental Setting and Direct Impacts** to the PVID, the groundwater-surface water hydrology presents a somewhat unique situation because of the BEP II project location within the PVID service area. The Colorado River groundwater the project will pump and consume from wells located on the Mesa and within both the PVID service area boundary and the USBR accounting surface, represents groundwater that will not flow into the PVID irrigation drains in the Valley. Groundwater that does not enter the drains will not be returned to the Colorado River and will not be accounted for as water credited to the PVIDs based on the diversion less return accounting system in current use.

When the groundwater-surface water hydrology is considered, unauthorized use in the general sense would not occur since the consumptive use of this Colorado River groundwater would be indirectly accounted for by diversion less return within the PVID service area. However absent an effective mitigation plan that either quantitatively mitigates the project's use of this water or eliminates it, both PVID's water entitlement and the State's Colorado River water supply would be quantitatively decreased by the amount of the 3300 acre-feet per year of water consumptively used by the BEP II project.

RWQCB WDRS FOR WASTE DISCHARGE TO EVAPORATION PONDS

Staff is unable to determine if the proposed project design and operational plan will comply with required WDRs. To make this determination the Applicant must provide staff final draft WDRs from the RWQCB at least 60-days prior to the Final Staff Assessment for review. Staff has determined the Applicant has submitted inaccurate calculations for the design of the evaporation ponds to the RWQCB. Staff is working with the RWQCB to obtain accurate calculations from the Applicant to ensure the evaporation ponds are correctly designed in order to avoid significant impacts, and be in compliance with applicable LORS.

STORM WATER NPDES PERMIT

Staff does not agree with the information the Applicant used to calculate the capacity of the storm water detention basin. Staff will need to confirm correct design calculation for the basin are provided to staff and to the City of Blythe, and used in the SWPPP required by the RWQCB. The BEP II will be required to secure a Construction and General Industrial Storm Water NPDES permit from the RWQCB before beginning construction of the power plant or any related component. BEP II must comply with the NPDES requirements that regulate storm water effluent limitations, monitoring, and reporting for construction activities and for industrial (operational) activities. BEP II must supply a Notice of Intent to the SWRCB to operate under both General NPDES Storm Water Permits for Construction and Industrial Activities. The Applicant must submit copies of the accepted notices for construction and operational storm water discharge prior to site mobilization and prior to operation, respectively.

FACILITY CLOSURE

The BEP II project is expected to operate for a minimum of 30 years. Closure options range from “mothballing,” with the intent of a restart at some time, to the removal of all equipment and facilities.

The decommissioning plan will be submitted to the Energy Commission for approval prior to decommissioning. Compliance with all applicable LORS, and any local and/or regional plans will be required. The plan will address all concerns in regard to potential erosion and impacts on water quality.

CONCLUSIONS AND RECOMMENDATIONS

DIFFERENCES BETWEEN BLYTHE I AND BLYTHE II

Although the Energy Commission licensed the BEP I project to use Colorado River groundwater, the following evolution of information and events have occurred since that project’s certification to not warrant the use of Colorado River groundwater.

1. The USBR’s abrupt suspension of surplus Colorado River water deliveries to the State on January 1, 2003 immediately cut California back from about 5.2 million acre-feet (MAFY) to 4.4 MAFY. Staff, and the rest of the State have had a rare opportunity to look into the future of the Colorado River water supply in the year 2016, and to experience the serious effects the loss of this water will cause.
2. The State’s use of Colorado River surplus water will be reduced through conservation and transfers from agricultural users, such as the PVID, to cities

including San Diego and Los Angeles. The BEP II project unnecessarily reduces the amount of Colorado River water available to the State by 3300 AFY, and by 100,000 AF over the 30 year life of the project.

3. A better understanding of the Colorado River surface water–groundwater system, particularly within the PVID service area, has lead to the determination that BEP II's use of Colorado River groundwater has associated significant direct and potentially significant cumulative impacts to the PVID and its users.
4. Because staff's Water Supply and Cooling Options Study (Appendix A) has determined that wet cooling of the BEP II power plant is not necessary, its use by the project represents an unreasonable use and waste of water.
5. Staff has determined, consistent with State law and policy, including the 2003 Energy Commission Integrated Energy Policy Report water policy, that fresh water is to be conserved and not wasted, and alternative water sources and alternative cooling technology such as that recommended for the BEP II project, is necessary to be consistent with these laws, regulations, and policies.
6. The WCOP, even an effective one, would not eliminate the projects unnecessary consumptive use of the State's Colorado River water supply, mitigate the project's associated significant impacts, or conform to State law and policy.

CONCLUSIONS

As proposed in the AFC, BEP II would cause significant water supply related direct and cumulative impacts, and would not conform to applicable LORS. Additional information is needed for water supply, transmission line linear facilities, stormwater, evaporation pond WDRs, well interference, and the **Unresolved Issues and Additional Data Needs** listed below for staff to complete its analysis and reach final conclusions on those aspects of the project.

- Staff has determined there will be a significant direct impact to the PVID water supply and its users, a significant cumulative impact to the State's Colorado River water supply and its users, and a potentially significant cumulative impact to the PVID water supply and its users that are directly related to the projects use of Colorado River groundwater.
- Neither the incomplete WCOP proposed, nor a complete and effective WCOP would mitigate or eliminate the project's consumptive use of Colorado River groundwater, and is an inadequate approach as a mitigation measure for the purposes of both CEQA and conformance to applicable LORS.
- Staff has performed a Water Supply and Cooling Options study, and determined that consumptive use of Colorado River groundwater is unnecessary for the purposes of cooling the power plant or other nonpotable uses.
- Staff concludes that because BEP II's use of Colorado River groundwater is unnecessary, it is, therefore, an unreasonable method of use and a waste of water under the provisions of the California Constitution Article X, Section 2, Water Code section 100, and does not conform to State water policy, including the 2003 Energy Commission Integrated Energy Policy Report water policy.

RECOMMENDATIONS

Because the BEP II project as proposed by the Applicant would cause significant impacts to the water supply and its users, would not conform to applicable LORS and State policy, and there is a feasible alternative to the use of Colorado River groundwater, staff recommends the project be amended to use the Dry Cooling alternative developed in the Water Supply and Cooling Options Study (Appendix A), or equivalent. The Applicant should submit an amended project design and operational plan for the BEP II project (Amended AFC).

UNRESOLVED ISSUES AND ADDITIONAL DATA NEEDS

This section reflects information that has been identified, or actions necessary by the Applicant and not yet taken that are needed for staff to complete its analysis.

1. Discharge of wastewater from the BEP II facility to the proposed evaporation pond could result in potentially significant impacts to soil and groundwater quality as a result of leaks or overflows from the proposed evaporation pond. Corrected evaporation pond calculations are needed, and should also be submitted to the RWQCB.

1. Draft WDRs for the evaporation ponds are needed at least 60 days prior to the date the FSA is scheduled for publication.

1. The plant operator can have the ability to regulate annual water consumption by management of plant output, particularly in regard to auxiliary firing. Auxiliary firing increases load on the steam turbine cycle portion of the plant that requires the cooling of the main condenser. Staff can not predict auxiliary firing amounts, since the AFC has not specified the amount of auxiliary firing. The Applicant should quantify the amount of auxiliary firing and reflect it in the heat and water balances.

2. Heat balances use spray cooling of gas turbine inlet air, the water balances appear to show cooling towers, and later submittals indicate that mechanical refrigeration type gas turbine inlet cooling is proposed. Variations in gas turbine inlet cooling can cause a 5% variation in water consumption. Variations in auxiliary firing can cause a greater variation. Inlet cooling should be reflected in the heat and water balances.
3. Construction and operations at the BEP II site could result in increased stormwater runoff volumes and peak flowrates leaving the BEP II site resulting in potentially significant impacts. The Applicant must provide revised design calculations that demonstrate the proposed retention basin can contain the runoff produced by a 100-year event and meet the City of Blythe's freeboard requirements by submitting corrected stormwater retention basin design calculations.
4. The Applicant must revise the retention basin design to include an emergency spillway or outlet structure to safely route potential overflows away from the containment berm.

Data or Actions Needed for the Proposed Project Design With WCOP

Although an alternative to the proposed project has been recommended by staff, these data or actions are needed in addition to those above for staff to complete its evaluation of the proposed project design with the WCOP, to the extent necessary. These additional data and actions are not necessary if the preferred Dry Cooling alternative is required.

5. Staff needs all of the available groundwater quality data that has been has identified requested by staff.

6. Staff needs the full report on the 2002 groundwater quality sampling of BEP I production wells, including the results for analytes that did not exceed the primary or secondary drinking water standards. A related issue, the Blythe Lemon Ranch gasoline leak, may require further evaluation for potential significant impacts related to entrainment and migration of any contaminate plume.

7. Reasonably quantitative conservation of water by the WCOP can not be determined because there is no complete and comprehensive actual plan available for evaluation. Wind and water born soil erosion related potentially significant impacts to fallowed lands could occur due to inadequate mitigation measures not consistent with NRCS recommended guidelines. A complete WCOP is needed that includes detailed procedures for implementation, management, monitoring, reporting, and verification of its effectiveness for both quantitative conservation of 3300 AFY of Colorado River groundwater and mitigation of erosion related potentially significant impacts to fallowed lands. The complete draft WCOP should be made available for review and comment by agencies to include the USBR, CRB, PVID, and NRCS at least 60 days prior to the date scheduled for publication of the FSA. Responses to unanswered Staff Data Requests, and/or additional data requests resulting from review of the complete WCOP by staff and other agencies may be necessary to complete the staff analysis.

PROPOSED CONDITIONS OF CERTIFICATION

Given the unmitigated significant impacts and nonconformance with LORS determinations and the **Unresolved Issues and Additional Data Needs**, staff can not propose conditions related to the water supply, WCOP, and well interference. Staff recommends the project not be licensed without the following conditions.

SOIL and WATER 1: The project owner shall comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan for the construction of the entire project (construction SWPPP). The project owner shall submit copies to the CPM of all correspondence between the project owner and the RWQCB regarding this permit.

Verification: The project owner shall submit copies to the CPM of all correspondence between the project owner and the RWQCB about the General NPDES permit for the Discharge of Storm Water Associated with Construction Activities within 10 days of its receipt (when the project owner receives correspondence from the RWQCB) or within 10 days of its mailing (when the project owner sends correspondence to the RWQCB).

This information shall include copies of the Notice of Intent and Notice of Termination for the project.

SOIL and WATER 2: Prior to beginning any site mobilization activities for any project element, the project owner shall obtain CPM approval for a site-specific Drainage, Erosion and Sedimentation Control Plan (DESCP) that addresses all project elements and ensures protection of water quality and soil resources. This plan shall address appropriate methods and actions, both temporary and permanent, for the protection of water quality and soil resources, demonstrate no increase in off-site flooding potential, meet local requirements, include legible drawings, details and complete narrative and identify all monitoring and maintenance activities. No later than 60 days prior to start of any site mobilization, the project owner shall submit a copy of the plan to Riverside County and the City of Blythe for review and comment. Any comments shall be provided to the CPM within 30 days of receipt of the plan. The plan must be approved by the CPM prior to start of any site mobilization activities. The plan shall be consistent with the grading and drainage plan as required by **Condition of Certification CIVIL-1** and may incorporate by reference any SWPPP developed in conjunction with any NPDES permit.

Verification: No later than 60 days prior to the start of any site mobilization for any project element, the project owner shall submit the DESCP to the CPM for review and approval. During construction, the project owner shall provide a report in the monthly compliance report on the effectiveness of the drainage, erosion and sediment control activities and the results of monitoring and maintenance activities. Once operational, the project owner shall provide in the annual compliance report information on the results of monitoring and maintenance activities.

SOIL and WATER 3: The project owner shall comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity. The project owner shall develop and implement a Storm Water Pollution Prevention Plan for the operation of BEP II (operation SWPPP). The project owner shall submit copies to the CPM of all correspondence between the project owner and the RWQCB related to this permit.

Verification: The project owner shall submit copies to the CPM of the operational SWPPP prior to commercial operation and all correspondence between the project owner and the RWQCB about the General NPDES permit for Discharge of Storm Water Associated with Industrial Activity within 10 days of its receipt (when the project owner receives correspondence from the RWQCB) or within 10 days of its mailing (when the project owner sends correspondence to the RWQCB). This information shall include a copy of the Notice of Intent and Notice of Termination.

SOIL and WATER 4: The project owner shall comply with all of the requirements of the RWQCB to discharge wastewater to the project's evaporation ponds. The project owner shall maintain RWQCB Waste Discharge Requirements for these ponds, and shall not discharge any waste to the evaporation ponds without final WDRS in place. The project owner shall report to the CPM any notice of violation, cease and desist order, cleanup and abatement order, or other enforcement action taken by the RWQCB related to the WDRs within 10 days of notice by the RWQCB. The project owner shall describe all actions taken to correct violations and operate the project in compliance with WDRs permit conditions. The project owner shall provide verification from the RWCQB that any violations have been resolved to the satisfaction of the RWQCB within 10 days of such determination.

Verification: Final RWQCB WDRs must be received by the CPM prior to start of commercial operation and/or discharge of waste to the ponds. The project will not discharge wastewater to the ponds without WDRs in place at any time.

SOIL and WATER 5: The on-site septic system shall be designed and operated to prevent any adverse impacts to water quality. Sixty days prior the start of commercial operation and/or discharge of waste to the septic system the project owner shall provide the CPM with verification from Riverside County and the City of Blythe that the septic system design and operational plan comply with County an City standards. Waste shall not be discharged to the septic system without these verifications being provided to the CPM.

Verification: No later than sixty days prior to start of commercial operation and/or discharge of waste to the septic system the project owner shall submit the verifications from the County and City to the CPM.

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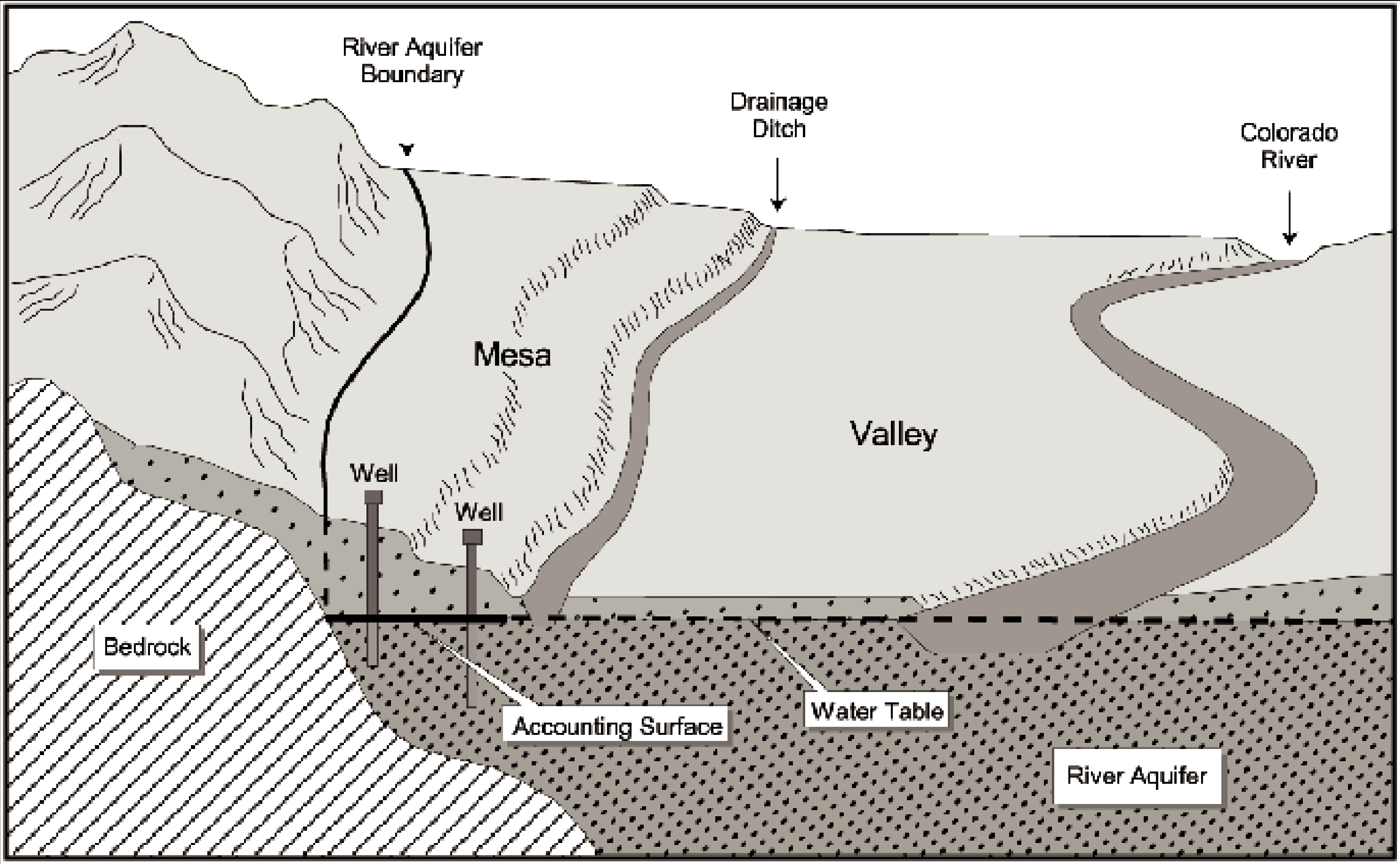
SOIL AND WATER RESOURCES RESOURCES - Figure 1

Blythe Energy Project II - Schematic Diagram Showing the River Aquifer and Accounting Surface

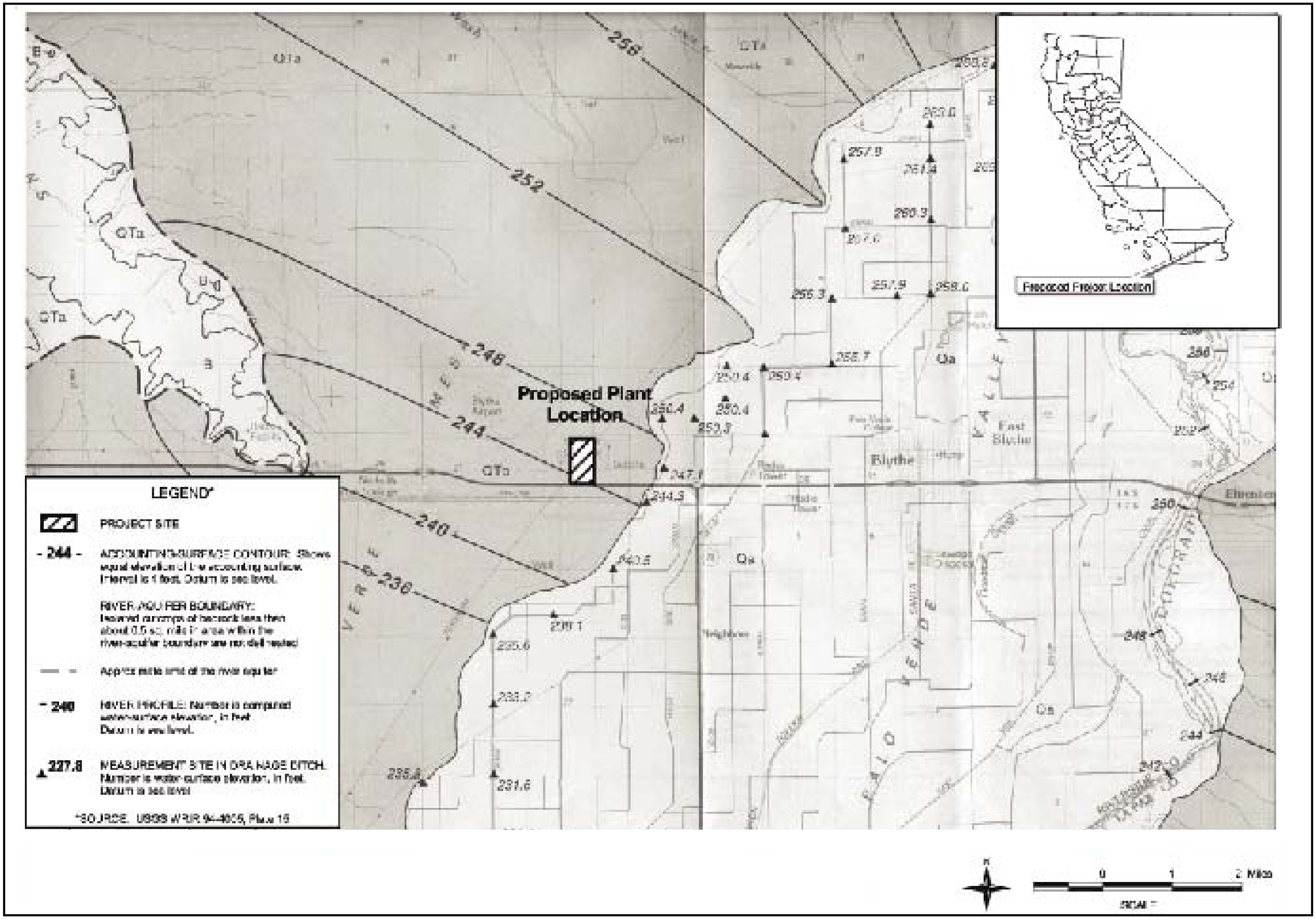


Mesa wells that have a static water-level elevation equal to or below the accounting surface are presumed to yield water that will be replaced by water from the Colorado River.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: LD BOND AND ASSOCIATES

SOIL AND WATER RESOURCES RESOURCES - Figure 2
Blythe Energy Project II - Colorado River Accounting Surface



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: USGS

SOIL AND WATER RESOURCES APPENDIX A

BLYTHE II ENERGY PROJECT

WATER SUPPLY AND COOLING OPTIONS

Testimony of James Schoonmaker and John Kessler

EXECUTIVE SUMMARY

In order to consider options to avoid the significant direct and significant cumulative impacts to other users of Colorado River water, Staff analyzed the following water supply and cooling alternatives in detail in comparison to the proposed project:

The Proposed Project – Use of Colorado River Groundwater with Wet Cooling;

Alternative 1 – Reclaimed Water from City of Blythe's Wastewater Treatment Plant (WWTP) with Wet Cooling;

Alternative 2 – Irrigation Return Water from PVID with Wet Cooling;

Alternative 3 –Irrigation Return Water from PVID with Hybrid Cooling (1/3 Wet/2/3 Dry);

Alternative 4 – Dry Cooling;

All use of water in the Proposed Project and Alternatives 1, 2 and 3 results in the use of Colorado River water and contributes directly to the significant shortage of local and regional Colorado River water supply. From a water conservation standpoint and to achieve consistency with state regulations and policies including those of the CEC, dry cooling would accomplish the highest conservation of Colorado River water, reducing average annual water use from 3,262 acre-feet/year (AFY) to about 40 AFY. No new water supply infrastructure (wells, pumps or off-site pipelines would be needed, as the minimal 40 AFY needed to support dry cooling could be made available using the existing BEPI infrastructure. Staff believes conservation of water supplies throughout California, but particularly in the Colorado River basin, is imperative, considering that all of California's entitlements from the Colorado River are fully allocated and the need to preserve Colorado River water is paramount in light of California being mandated to reduce its historical use by over 1 million acre-feet/year.

Based on the compilation of environmental and engineering measures presented in Soil and Water Resources Appendix Table 8, staff believes Alternative 4 – Dry Cooling is a preferable alternative to the proposed use of Colorado River groundwater and wet cooling (Proposed Project).

Staff has identified potentially significant adverse impacts associated with the Proposed Project in the following three areas:

1. <u>Land Use</u> - Due to loss of production of local agricultural lands;

2. Socioeconomics – Due to fallowing 1,617 acres in the Mesa Verde area to allow for water usage by BEP I and BEP II, which could result in a significant impact on the local economy and a disproportionate impact to an environmental justice community whose livelihood is largely dependent upon agriculture.
3. Water Resources – Due to inconsistency with LORS and significant direct and significant cumulative impacts to other users of Colorado River water;

Accounting for financial elements and no lost power effects from hybrid or dry cooling, all alternatives are equivalent in cost to the proposed project. Even when accounting for lost power generation, the incremental effect on the cost of power production is only about .0006 cents to .0012 cents per KWH higher (assuming power values ranging from $30 to $60 per MWH) to implement dry cooling compared to the proposed project. Neither of these increments of cost will significantly affect project economics or the owner's ability to market power. While Dry Cooling would require an additional capital investment of about $12 million over the capital cost of the proposed project, annual BEP II O&M costs are about $800,000 less for Dry Cooling compared to the proposed project, which effectively makes the alternatives comparable in out-of-pocket cost over the life of the project.

1. INTRODUCTION

The Blythe II Energy Project (hereafter abbreviated BEP II), as proposed, is a nominal 520 MW combined cycle power plant using two gas turbines and one steam turbine. AFC information is based on a Siemens V84.3 Combined Cycle. As proposed, the plant includes a cooling system using wet (evaporative) cooling towers, which would use an average of 3,262 acre-feet/year (AFY) of groundwater from on site wells. Groundwater used by this project is replaced by Colorado River water and is hereafter referred to as Colorado River groundwater. The Applicant proposes to avoid discharge of process wastewater from BEP II by utilizing a brine concentrator, which separates water suitable for reuse from the brine waste conveyed to the evaporation ponds.

1.1 PURPOSE OF REPORT

The purpose of this report is to consider alternatives to the proposed cooling system and water supply for BEP II (02-AFC-01).

The analysis of alternative water sources for BEP II was undertaken to determine if feasible options exist to the proposed use of Colorado River groundwater. The analysis of cooling options was undertaken to determine whether there are available cooling technology options that would reduce the demand for water. Two potential sources of reclaimed or degraded water (City of Blythe's treated wastewater and PVID's irrigation return flows) and two cooling technology options (dry cooling and hybrid cooling) are considered in detail as alternatives to the proposed project. In addition, an alternative source of water supply, the Lower Colorado Water Supply Project, is considered briefly, and dismissed as not being available to the BEP II Project.

Applicable LORS have been discussed and addressed in the PSA. Unless otherwise noted, the alternatives have been considered for consistency with LORS.

1.2 REPORT CONTENTS

This report consists of six parts and a sub-appendix and is organized as follows:

Introduction

Part 1 describes the purpose of the report, the cooling water supply and technology options and other report contents.

Potential Alternative Water Sources

Part 2 describes in detail the availability of wastewater that may be reclaimed from the City of Blythe's wastewater treatment plant and the availability of degraded water from Palo Verde Irrigation District's (PVID's) irrigation return water. In addition, water supply from the Lower Colorado Water Supply Project is considered and then dismissed as not being available to the BEP II Project.

Conceptual Designs of Cooling Technology Options

Part 3 describes potential designs for dry and hybrid cooling systems at the BEP II.

Cost Comparison and Engineering Measures for Water Conservation

Part 4 describes the engineering technologies or measures that could reduce the amount of water used at BEP II. This section also discusses the feasibility and cost of implementing these water-conserving measures.

Environmental and Engineering Analysis

Part 5 analyzes the environmental and engineering effects of the different cooling technologies and the use of degraded water from both City of Blythe's wastewater treatment plant and PVID's irrigation return drains for each of the technical issue areas that would be substantially affected (e.g. noise, visual and air quality).

Conclusions

Part 6 presents overall conclusions about the environmental and engineering effects of the cooling and water supply options at BEP II.

Background on Water Supply and Cooling Options

Appendix A.1 provides an overview of water use at the BEP II and the water supply and cooling options considered in this report: (dry cooling, wet cooling, hybrid cooling and the use of reclaimed or degraded water for power plant cooling). It describes the basic technologies and how they work, where the technologies are currently used, and the advantages and disadvantages of each.

Glossary of Terms

This section relates to this Appendix only.

2.0 POTENTIAL ALTERNATIVE SOURCES OF WATER SUPPLY

Three alternative sources of water supply are considered as alternatives to the proposed Colorado River ground water for the BEP II cooling water demand of 2.4 mgd average and 4.0 mgd maximum. Two of these sources are considered in detail and include reclaimed water from the City of Blythe's Wastewater Treatment Plant (WWTP) and Irrigation Return Water from Palo Verde Irrigation District (PVID). The third alternative source of water supply from the USBR's Lower Colorado Water Supply Project is analyzed in less detail because staff has determined that BEP II is not eligible to receive this water. Availability and cost for each potential viable source is compared to the use of Colorado River ground water. Only irrigation return water from PVID is currently available in sufficient quantities to meet 100% of BEP II demands beginning in 2006, the earliest date the project could operate if approved by the commission. The water supply and cooling alternatives that are being analyzed in detail in comparison to the proposed project are summarized as follows:

2.1 PROPOSED PROJECT – USE OF COLORADO RIVER GROUND WATER SUPPLY WITH WET COOLING

As discussed in the Soil and Water Resources Technical area of this PSA, the USBR, CRB, PVID, and CEC staff are all in agreement that the proposed use of groundwater by BEP II is replaced with Colorado River water.

PVID's contract with the USBR dated February 7, 1933 specifies that in addition to entitlements for Priority 1 water supply, that PVID is also entitled to Priority 3 water supply from the Colorado River for use exclusively on 16,000 acres in the area known as the Lower Palo Verde Mesa (Mesa) for beneficial consumptive use. The Mesa is the location for the proposed BEP II Project. PVID also has a Priority 6b for an additional 16,000 acres on the Mesa during surplus water years. PVID is entitled to divert both Priority 1 and 3 water at the Blythe Intake on the Colorado River. There is no charge for the water, and PVID is responsible to convey water for use within its District. PVID believes that its Priority 1 and 3 water is not limited to a single purpose of use such as for only irrigation, but rather can be applied for any beneficial consumptive use including industrial purposes.

PVID's current use of its Priority 3 water from the Colorado River is applied to the Mesa for irrigation of 2,000 – 3,000 acres of primarily citrus crops, supplying a gross volume of about 16,000 AF before accounting for returned water. PVID believes it has entitlement through its Priority 3 allocation to supply water to BEP II. This water could potentially be conveyed either from its irrigation or drainage canals extended with a pipeline to BEP II, or by groundwater pumping directly from the BEP II site.

PVID believes some groundwater under the Mesa is recharged by irrigation on the Mesa with canal water pumped from the valley and by under flow from valley groundwater, drains, and canals. Valley groundwater is further augmented with Colorado River water by the irrigation applications within PVID's district, which percolate to groundwater.

PVID is typically credited for over 400,000 AF/yr of return water it collects in its drains and discharges back into the Colorado River as part of its determination of net Colorado River water use comprised of diversion less return. PVID believes that any groundwater withdrawn by BEP II would be accounted for indirectly by reducing PVID's return, and in essence is a utilization of PVID's Priority 3 water (due to the proposed location of use by BEP II being on the Mesa).

PVID believes that the accounting of groundwater use from the Mesa as part of PVID's diversion less return has been ongoing since before 1972 when a cone of depression from other Mesa groundwater users became apparent. The depression in the water table results in a groundwater flow gradient towards the Mesa from the valley which they believe is supplied by irrigation on the Mesa with canal water pumped from the valley and the valley's groundwater that is recharged by valley irrigation applications. Staff's analysis in the Soil and Water Resources Technical area of this PSA confirms the existence of this surface-groundwater hydrological relationship.

PVID is of the opinion that a water supply contract between the BEP II Applicant and itself would be a more straight-forward way of accounting for BEP II's water use. Since this water would be counted against PVID's surface water entitlement, staff agrees that PVID should be compensated for BEP II's groundwater withdrawals. PVID currently charges $85/acre-foot for water supplied for irrigation purposes. The proposed BEP II Water Conservation Offset Program (WCOP) is intended to provide the volume of water needed by the plant by taking active agricultural land out of production so the net change in water use would be zero. In a similar WCOP, Metropolitan Water District (MWD) is proposing to export a portion of PVID's Colorado River allocation for municipal and industrial purposes subject to a fallowing agreement with local farmers within PVID's district. Staff's understanding of the primary terms of MWD's fallowing agreements with local farmers in PVID's district, are as follows:

1. Term of 35 years;
2. Initial payment of $3,250 per acre;
3. Annual payment of $500 per acre;
4. Acreage totaling approximately 25,000 acres;

Based on an average water use of 4.2 acre-feet per acre of land, the annual cost of MWD's water is about $120 per acre-foot after the initial one-time fee of $3,250 per acre. Since the Applicant has not apparently negotiated financial terms for its WCOP, staff is using MWD's costs as being representative for BEP II.

2.2 RECLAIMED WATER FROM CITY OF BLYTHE'S WWTP WITH WET COOLING – ALTERNATIVE 1

The City of Blythe's Wastewater Treatment Plant (WWTP) was placed into operation in 1979 at an initial capacity of 1.5 mgd. The existing capacity of the City's WWTP is 2.4 mgd. The wastewater collection system includes several lift stations for conveying wastewater to the WWTP. During 1991 and 1992, the City initiated a Wastewater Treatment Facility Analysis to consider alterations needed to improve the reliability of meeting its discharge criteria as well as to increase its capacity to meet projected populations to the year 2010. In 1992, the City's population was 11,100 with average daily flows of 1.1 mgd in winter and 1.6 mgd in summer. In 2003, the City's population is about 14,000 (excluding the approximately 8,000 inmates at the Ironwood and

Chuckwalla State Correctional Facilities which are located about 16 miles west of the City) with average daily flows of 1.5 mgd in winter and about 2.1 mgd in summer. As of 1992, the projected population for 2010 was 17,070 or an average annual increase from 1990 to 2010 of 2.2%/year. The projected 2010 WWTP flows were expected to result in average daily flows of 1.7 mgd in winter and 2.5 mgd in summer using Per Capita Unit Flow values of 95 gallons per capita day (gpcd) during winter and 140 gpcd in summer. If City of Blythe's population continues to grow at the same average annual rate of 2.2%/year, population in 2020 and 2030 would be 21,220 and 26,380 respectively. The corresponding WWTP average dry weather flows for winter and summer would be 2.0 mgd winter and 3.0 mgd summer by 2020 and 2.5 mgd winter and 3.7 mgd summer by 2030. (Blythe 1992 & Blythe 2003)

The City of Blythe treats its wastewater to advanced secondary treatment and discharges its effluent into percolation ponds located onsite at the WWTP, which serve to recharge the groundwater aquifer (and is returned to the Colorado River). TDS concentration of the wastewater effluent is about 1,185 mg/l. PVID believes the City of Blythe's wastewater effluent percolating to groundwater contributes to the flows returning to the Colorado River, which effectively reduces PVID's use of Colorado River water as accounted for by USBR (PVID 2003a).

To meet current Title 22 regulations for use of reclaimed water for industrial cooling at BEP II, the effluent from City of Blythe's Wastewater Treatment Plant would need to be upgraded from advanced secondary to tertiary treatment. At this time, City of Blythe has neither any plans for upgrading its wastewater treatment plant to tertiary treatment nor plans for employing a reclaimed water program. Even though the Applicant could possibly fund this expense, or at least fund its proportionate share of the cost to implement tertiary treatment, this is not likely to occur.

Staff's view is that Alternative 1 – Reclaimed Water from City of Blythe's WWTP with Wet Cooling is not presently a viable alternative due to the following:

1. The potential supply of reclaimed water is not sufficient to meet BEP II demands over the life of the project, while other sources of lesser quality water already exist (See Soil & Water Resources Appendix Tables 2 and 3 below).
2. City of Blythe does not have any existing or foreseeable plans to implement Title 22 tertiary wastewater treatment or a reclaimed water program.
3. The use of reclaimed water would essentially be use of Colorado River water.

City of Blythe's Pipeline Route to BEP II

A specific pipeline route was not selected for this alternative because staff believes adequate information already exists to dismiss it from being considered a preferred alternative for BEP II water supply. If a pipeline route had been identified, it would have been approximately 4.5 – 5 miles in length to convey reclaimed water from City of Blythe's WWTP to BEP II. A conceptual cost for the pipeline and associated water supply costs has been included.

2.3 IRRIGATION RETURN WATER FROM PVID WITH WET COOLING – ALTERNATIVE 2

PVID operates a system of irrigation supply and return (drainage) ditches. The drainage ditches are about 10 to 20 feet deep in order to intercept groundwater averaging (valley wide) about 10 feet below the ground surface. As water is applied to crops for irrigation, excess irrigation water is applied to keep salts from building up in the soil. Excess water percolates into the ground to reach ground water. Ground water then flows to the drainage channels and is returned to the Colorado River.

In total for all of PVID's drainage system, irrigation return flows normally range from a minimum average daily flow of 280 cfs during January to 800 cfs during summer. In the vicinity of BEP II along the Rannells Drain, the irrigation return flows normally range from a minimum average daily flow of 2 cfs during January to about 15 cfs during the balance of year. Minimum flows occur during a 2-week annual outage of the irrigation supply canals, and otherwise, irrigation supply (and thus irrigation return) occurs at higher flows for the balance of the year. (PVID 2003b) The rate and pattern of flow in PVID's irrigation return drains is not expected to significantly change as a result of the recently approved Quantification Settlement Agreement (QSA).

Flow in the Rannells Drain is made-up of intercepted shallow groundwater (after being applied for irrigation) and operational spillage from Canal B, a source of irrigation supply for the immediate area. Flows in the Rannells Drain in excess of 2-3 cfs contributed from intercepted shallow groundwater typically reflect some irrigation spillage from Canal B. Intercepted groundwater in the Rannells Drain is a function of the extent of adjacent lands being irrigated for agriculture. Therefore, the quality of water in the Rannells Drain is largely influenced by local agriculture activity (which degrades the drainage water quality) and Canal B irrigation spillage (which enhances the drainage water quality). As an indication of water quality in the Rannells Drain, PVID's observed TDS was 1,510 mg/l on an undisclosed date in September 2002 and 1,590 mg/l on March 14, 2003. In comparison, irrigation water diverted from the Colorado River on those dates was observed to have TDS concentrations of 552 mg/l and 728 mg/l respectively (PVID 2003d). PVID typically collects water quality data on a quarterly basis for its irrigation supply as diverted from Colorado River and on a bi-annual basis for its irrigation return flows in Rannells Drain (PVID 2003d).

In comparison, average and peak water demands for BEP II are 3.5 cfs (2.4 mgd) and 6.2 cfs (4.0 mgd). PVID indicated that during its normal 2-week outage in January that it could make special arrangements to provide continuity for meeting BEP II's water demands. Whether water for BEP II comes from drain, irrigation canal or groundwater, water from any of these sources would be accounted for under PVID's water right. PVID currently charges $85/acre-foot for water supplied for irrigation purposes (PVID 2003a, PVID 2003b).

<u>PVID's Pipeline Route to BEP II</u>

Alternative 2 – Irrigation Return Water from PVID would require construction of an approximately 1.5 mile water supply pipeline from a turnout on PVID's Rannells Drain to BEP II. The pipeline would be expected to follow one of the two alternative routes described below. (See **Soil & Water Resources Appendix Figure 1** at the end of this report for the Alternative A & B pipeline routes)

Pipeline Route Alternative A (1.5 miles)

- Beginning at a new turnout from Rannells Drain adjacent to 12th Ave., and approximately 0.5 miles west of Highway 78;
- West approximately 1.0 mile along Riverside Drive, which turns to Chanslor Way (12th Ave.) to the northern boundary of the BEP II site;
- Inside the project boundary, the pipeline would run along the property centerline in a southerly direction to tie-in to the BEP II water tank.

Pipeline Route Alternative B (1.5 mile)

- Beginning at a new turnout from Rannells Drain adjacent to Hobsonway, and approximately 0.5 miles west of Highway 78;
- West approximately 1.0 mile along Hobsonway to the southern boundary of the BEP II site;
- Inside the project boundary, the pipeline would run along the property centerline in a northerly direction to tie-in to the BEP II water tank.

Conveyance of the irrigation return water via one pump station located at the new turnout from Rannells Drain would likely be the most economical arrangement. The pump station would require an area of about 0.1 acres to accommodate parking, a wet well (underground sump) for submerging the pump inlets, a small housing to cover pumping equipment and controls, and to provide electrical service. Electrical service would be extended using wood poles and overhead line.

The water pipeline would be constructed within appropriate rights-of-way. Along paved roads, the pipeline would be constructed preferably along the shoulder, so as to work within the existing road easement and areas already affected by the road. This would also avoid or minimize disturbance to vehicle travel. Through agricultural fields, the pipeline would be constructed within existing public utility easements or within or along the shoulder of agricultural access roads wherever possible. If the pipeline requires any road crossings, construction of 2 – 5 days duration would be staged to allow vehicle traffic to share a minimum of a single lane. The trench dimensions would generally be about 4 feet wide by 5 feet deep. Temporary construction disturbance along the pipeline route would average about 50 feet wide, for a total of about 6 acres. Along the water pipeline route, the surface would be restored to existing conditions. No new permanent access roads would be required.

2.4 IRRIGATION RETURN WATER FROM PVID WITH HYBRID COOLING – ALTERNATIVE 3

Using Irrigation Return Water from PVID with Hybrid Cooling – Alternative 3 is similar to Alternative 2 - Irrigation Return Water from PVID with Wet Cooling, except for the demand for cooling water is reduced to about one third of the average annual demand of a wet cooling system, or about 1,100 AFY rather than 3,300 AFY respectively.

2.5 DRY COOLING – ALTERNATIVE 4

Dry cooling would require only about 40 AFY and thus could rely on the existing BEPI water system, and avoid any new infrastructure or disturbance outside of the BEP power plant boundaries.

2.6 USBR'S PROPOSED LOWER COLORADO WATER SUPPLY PROJECT

The Lower Colorado Water Supply Project (LCWSP) was authorized by Congress in 1986 to supply water for domestic, municipal, industrial, and recreational purposes. The eligible beneficiaries are limited to persons or agencies whose lands or interests in lands are located adjacent to the Colorado River in California within the accounting surface, who do not hold rights to Colorado River water or whose rights are insufficient to meet their present or anticipated future needs. The project consists of well fields in the Sand Hills along the All American Canal in Imperial County, and will have an ultimate capacity to supply up to 10,000 afy. Currently, Phase 1 of the project, which has developed capacity for half, or 5,000 afy of the ultimate capacity, has contracted for 3,500 afy for the City of Needles and 1,150 afy for the U.S. Bureau of Land Management, leaving 350 afy of unallocated existing capacity and 5,000 afy of additional capacity yet to be developed. Imperial Irrigation District assumed the operation and maintenance responsibilities for the Phase I project beginning in 2000.

The process for obtaining water from the LCWSP begins by submitting an application to the Colorado River Board (CRB). After reviewing the application, the CRB provides its recommendation to USBR. If approved by USBR, the City of Needles who serves as USBR's contractor, is contacted to administer the subcontract. An initial cost of \$300 per acre-foot is assessed for the subcontract quantity of water, as well as an annual cost of about \$250 per acre-foot for project operations and maintenance. LCWSP water is delivered via existing water conveyance facilities using a portion of Imperial Irrigation District's or Coachella Valley Water District's Colorado River entitlements in exchange for an equivalent quantity and quality of groundwater as developed by the LCWSP.

Water for agricultural uses is not available from the LCWSP, nor is supply within an existing purveyor's service area where adequate water supplies already exist. In the case of BEP II, because it is located within PVID's service area, it is not eligible to be supplied by the LCWSP. Therefore, this alternative was not explored further. (CRB 2003a)

2.7 PROJECTED QUALITY & QUANTITIES OF ALTERNATIVE WATER SUPPLIES COMPARED TO BEP II DEMANDS

The availability of alternative water supplies from the City of Blythe's WWTP and PVID's irrigation return flows is presented by time increments (2003 to 2030) in **Soils and Water Resources Appendix Table 1**. Also presented is the amount of supplemental water that would be needed to supplement the alternative water in order to meet the average and peak demand requirements of BEP II. In addition, the table identifies the amounts of fresh or alternative water that would be required using the wet evaporative cooling towers as proposed by the applicant and alternative hybrid and dry cooling approaches.

Soil & Water Resources Appendix Table 1
Comparison of BEP II's Dependency on Fresh Water & Availability of Alternative Water Supplies based on Average & Peak BEP II Demands (mgd)

Source	2003	2006	2010	2020	2030	TDS
Proposed Project – Use of Colorado River Groundwater with Wet Cooling @ BEP II Avg. Demands						
PVID's Groundwater	N/A	2.4	2.4	2.4	2.4	1010
Proposed Project – Use of Colorado River Groundwater with Wet Cooling @ BEP II Peak Demands						
PVID's Groundwater	N/A	4.0	4.0	4.0	4.0	1010
Alt. 1: Reclaimed Water from City of Blythe's WWTP with Wet Cooling– Winter Flows @ BEP II Avg. Demands						
City of Blythe's Wastewater	1.5	1.6	1.7	2.0	2.5	1185
Supplemental Water	N/A	0.8	0.7	0.4	0	
Alt. 1: Reclaimed Water from City of Blythe's WWTP with Wet Cooling – Summer Flows @ BEP II Peak Demands						
City of Blythe's Wastewater	2.1	2.3	2.5	3.0	3.7	1185
Supplemental Water	N/A	1.7	1.5	1.0	0.3	
Alt. 2: Irrigation Return Water from PVID with Wet Cooling – Winter Flows @ BEP II Avg. Demands						
PVID's Irrig. Return Water	2.4	2.4	2.4	2.4	2.4	1550
Supplemental Water	N/A	0	0	0	0	
Alt. 2: Irrigation Return Water from PVID with Wet Cooling – Summer Flows @ BEP II Peak Demands						
PVID's Irrig. Return Water	4.0	4.0	4.0	4.0	4.0	1550
Supplemental Water	N/A	0	0	0	0	
Alt. 3: Irrigation Return Water from PVID with Hybrid Cooling @ BEP II Avg. Demands						
PVID's Irrig. Return Water	N/A	0.8	0.8	0.8	0.8	1550

Alt. 3: **Irrigation Return Water from PVID with Hybrid Cooling @ BEP II Peak Demands**						
PVID's Irrig. Return Water	N/A	1.3	1.3	1.3	1.3	1550
Alt. 4: Dry Cooling @ BEP II Avg. Demands						
PVID's Groundwater	N/A	.04	.04	.04	.04	1010
Alt. 4: Dry Cooling @ BEP II Peak Demands						
	N/A	0.2	0.2	0.2	0.2	1010

Notes:
1) Assumes the average BEP II water supply requirements are 2.4 mgd for wet cooling, 0.8 mgd for 1/3 wet/2/3 dry hybrid cooling, and 0.04 mgd for dry cooling;
2) Assumes the peak BEP II water requirements are 4.0 mgd for wet cooling; 1.3 mgd for hybrid cooling, and 0.2 mgd for dry cooling;
3) Assumes the BEP II could begin operation by 2006, with average annual demands of 3,262 afy for wet cooling, 1,100 afy for hybrid cooling and 40 afy for dry cooling;
4) Colorado River water has a TDS concentration ranging from about 550 mg/l to 800 mg/l depending on season and hydrology.

Based on the above table, it is apparent that PVID's irrigation return water is the only alternative water source that will meet both average and peak demands for the proposed BEP II at the beginning of its projected operation in 2006. Reclaimed water from City of Blythe's WWTP is not projected to provide sufficient water supply to BEP II until around 2028 based on average daily flow and beginning around 2034 based on peak daily flow. In addition to considering the quantity of reclaimed water that may be available, other considerations include comparing water quality to understand the pre-treatment requirements, in addition to environmental impacts and cost. It is also apparent that the salinity (TDS) of PVID's irrigation return water is the highest compared to other sources of supply. **Soil & Water Resources Appendix Table 2** summarizes TDS concentrations for two water sampling periods collected by PVID, comparing the quality of Colorado River water to its irrigation return water

Soil & Water Resources Appendix Table 2
Observed Total Dissolved Solids (TDS) Measurements of Alternative Water Supplies (mg/l)

Location	September 2002	March 2003	Average
Colorado River Water @ PVID's Blythe Intake	552	728	640
Irrigation Return Water in Rannells Drain @ 24th Ave. Bridge	1,510	1,730	1,630
Total Irrigation Return Water @ the Colorado River Outfall	1,364	1,590	1,477

(PVID 2003d)

In comparison to the average TDS value of 1,630 mg/l shown above for irrigation return water in Rannells Drain, average values for City of Blythe's treated wastewater and the Mesa groundwater are 1,185 mg/l and 1,010 mg/l respectively. Clearly, in comparing water quality using TDS concentrations as an indicator, the irrigation return water in

Rannells Drain is lower in quality compared to the Proposed Project (using Colorado River groundwater) and Alternative 1 – Reclaimed Water from City of Blythe's WWTP.

2.8 CONSISTENCY OF ALTERNATIVE WATER SUPPLIES WITH LOCAL AGENCY POLICIES

Clarity of Entitlement, Availability & USBR Accountability

As an indicator as to whether water use in accordance with the proposed project and considered alternatives could negatively impact other more senior entitlements to use of Colorado River water, staff has assessed the clarity of entitlement, its availability, and the ability to demonstrate accountability of water use for each. The intent of this comparison is to show the following:

a) A clear link to a specific and recognized Colorado River entitlement,
b) Authorization for use of a specified amount of water by the party who possesses the entitlement, and
c) That BEP II's water use over time will be properly included in the accounting method for Colorado River allocations and use.

This assessment is summarized as follows:

Soil & Water Resources Appendix Table 3
Comparison of Entitlement, Availability & USBR Accountability of Alternative Water Supplies

Alternative	USBR Accountability
Proposed Project – Use of Colorado River Groundwater with Wet Cooling Average Annual Water Use = 3,262 AFY	Indirectly Accountable – a) Applicant has not linked its proposed use of groundwater with a USBR-recognized entitlement to use of Colorado River water. b) PVID has not formally authorized BEP II use of groundwater, because it does not normally regulate groundwater use within its District. c) USBR, USGS, PVID, CRB and staff believe Mesa groundwater is within the Colorado River accounting surface, yet USBR has no current methodology to account for groundwater use.
Alternative 1 - Reclaimed Water from City of Blythe with Wet Cooling Average Annual Water Use = 3,262 AFY	Indirectly Accountable – a) The treated wastewater is considered City of Blythe's use under PVID's entitlement until it is returned to groundwater via percolation ponds. After which, PVID considers the groundwater as part of its diversion less return of Colorado River water. b) City of Blythe and PVID would need to approve use of the treated wastewater. c) Reducing the return of treated wastewater to the groundwater aquifer is a less direct method of accounting for PVID's net use (diversion less return) than accounting for surface water in accordance with USBR's current procedures. USBR has no current methodology to account for groundwater use and returns.
Alternative 2 - Irrigation Return Water from PVID with Wet Cooling	Clearly Accountable – a) Linked to PVID's Priority 3 Colorado River water supply entitlement;

Average Annual Water Use = 3,262 AFY	b) PVID has indicated its willingness to supply Irrigation Return water; c) Included as part of PVID's Diversion less Return as monitored by USBR;
Alternative 3 - Irrigation Return Water from PVID with Hybrid Cooling Average Annual Water Use = 1,100 AFY	Clearly Accountable – a) Linked to PVID's Priority 3 Colorado River water supply entitlement; b) PVID has indicated its willingness to supply Irrigation Return water; c) Included as part of PVID's Diversion less Return as monitored by USBR;
Alternative 4 - Dry Cooling	Not Applicable

In considering the Proposed Project, staff believes that due to a lack of clarity for BEP II's proposed use in terms of entitlement, availability & USBR Accountability, that BEP II's use has significant direct and potentially significant cumulative impacts to other users of Colorado River water. Complicating the ability to account for groundwater use from the Lower Palo Verde Mesa (Mesa) is the following:

a) PVID does not currently regulate groundwater use within its District.

b) USBR has not implemented any generally applicable methodology to account for groundwater use within the Colorado River accounting surface.

c) The groundwater-surface water hydrology within the PVID indicates that consumptive use of Colorado River groundwater by the project will be counted against PVID's allocation based on diversion less return (see the Soil and Water Resources section of the Staff Assessment).

d) There is uncertainty whether PVID can legally provide Colorado River water to the project with a water supply contract (see Soil and Water Resources section of the Staff Assessment).

2.9 PROJECTED WATER CONVEYANCE COSTS OF ALTERNATIVE WATER SUPPLY & COOLING OPTIONS

Soil and Water Resources Appendix Table 4 below presents the design factors and approximate cost of constructing and operating the water supply pipelines and associated wells and pumping stations for each alternative.

Soil and Water Resources Appendix Table 4
Design Factors and Approximate Cost of Water Pipelines & Pumping

Description of Item	Proposed Project Colorado River Groundwater with Wet Cooling	Alt. 1 Reclaimed Water from City of Blythe's WWTP with Wet Cooling	Alt. 2 Irrigation Return Water from PVID with Wet Cooling	Alt. 3 Irrigation Return Water from PVID with Hybrid Cooling
Pipe material	No Pipeline	HDPE	HDPE	HDPE
Pipe Inside Diameter, Inches	Needed	30.0 / 18.0	30.0 / 16.0	20.0 / 10.0
Velocity @ 2,785 gpm, (6.2 cfs) fps		3.5	4.4	
Velocity @ 930 gpm, (2.1 cfs) fps				3.8
Friction loss, ft/100 ft		0.20	0.32	0.25
Length, ft		23,760	7,920	7,920
Friction loss, ft		48	25	20
Elevation gain, ft		100	90	90
Miscellaneous losses, ft		36	24	24
Total head, ft	150	184	139	134
Average pumping total power, BHp	175	220	165	55
Number of pump stations	1	1	1	1
Primary Pump Stations, typical pump Hp, 2 constant speed & 1 variable frequency	175 Hp / Pump (for 1 Well)	75 Hp / Pump	60 Hp / Pump	20 Hp / Pump
Pumping Energy @ 60 percent Duty Factor, 365 Days/yr, 24 Hours/day	686,000 KWH	863,000 KWH	647,000 KWH	216,000 KWH
Capital Cost Items				
Primary pump station or Well	600,000	450,000	400,000	300,000
Pipeline cost @$180/lf for 18-inch, & @$165/lf for 16-inch & $120/lf for 10-inch ID	0	4,280,000	1,310,000	950,000
Rannells Drain Turnout	0	0	150,000	100,000
Subtotal – Capital Costs	**600,000**	**4,730,000**	**1,860,000**	**1,350,000**
Engineering and services during construction @ 10%	60,000	473,000	186,000	135,000
Detail allowance & contingency @ 10%	60,000	473,000	186,000	135,000
Total Capital Cost	**$720,000**	**$5,676,000**	**$2,232,000**	**$1,620,000**
Water Pumping O&M Cost Items				
Annual pumping power cost @ $0.06/kWh	$ 41,000	$52,000	$39,000	$ 13,000
Annual maintenance	60,000	80,000	70,000	50,000
Annual labor	90,000	90,000	90,000	80,000
Total O&M Cost	**$191,000**	**$222,000**	**$199,000**	**$143,000**

Note: A cost of a water supply pipeline & pumping was not estimated for Alternative 4 – Dry Cooling because there would be no such infrastructure outside of the plant boundaries.

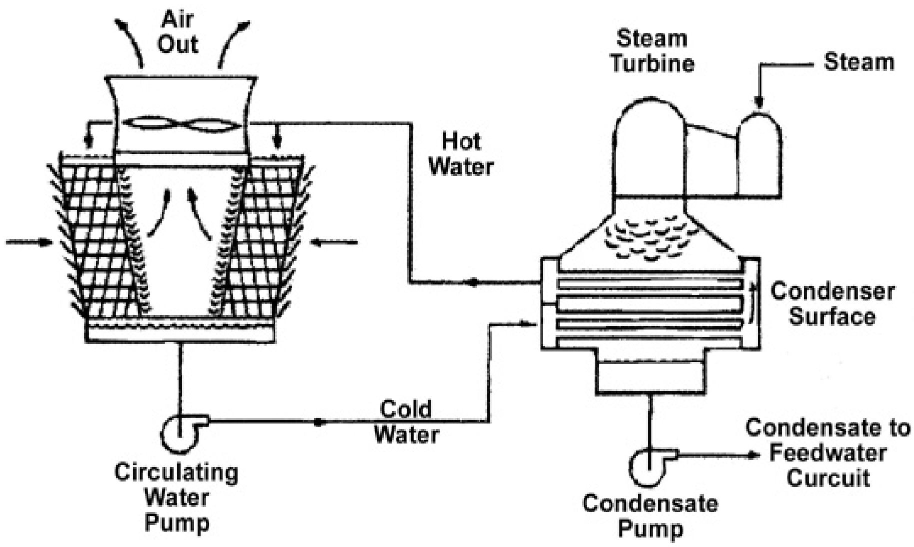
3. CONCEPTUAL DESIGNS OF COOLING TECHNOLOGY OPTIONS

3.1 EQUIPMENT REQUIRED AND BASIC CONFIGURATION

As discussed above, wet cooling towers are proposed in the AFC and Supplements. For comparison purposes, a schematic representation of the proposed main wet cooling system is shown below in **Soil & Water Resources Appendix Figure 2** (CEC/EPRI

2002). With this design, exhaust steam from the steam turbine is condensed by a “surface condenser”, which in turn is cooled by circulating water, which is cooled by the cooling towers.

Soil & Water Resources Appendix Figure 2
Wet Cooling System with Surface Condenser and Mechanical Draft Cooling Tower



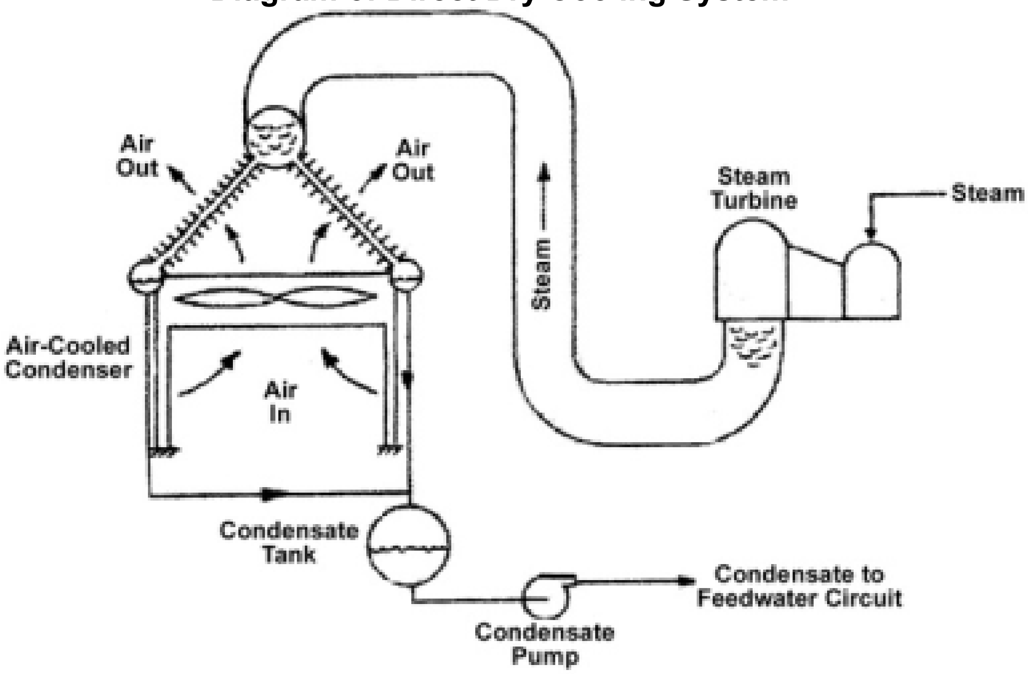
In the gas turbine inlet cooling system a similar diagrammatic representation can be used, by substituting the mechanical chiller system condenser for the steam turbine condenser. The chiller system condenses a refrigerant (ammonia or fluorocarbon) instead of steam, but is still very similar.

Dry cooling, or non-evaporative cooling, is accomplished using Air Cooled Condensers (ACCs). The ACC’s consist of multiple finned heat exchange tubes mounted on a large steel framework as shown in the schematic representation below in **Soil & Water Resources Appendix Figure 3**. An ACC is somewhat like an automotive radiator, but much larger. The cooling media is ambient air. Fans are used to draw air in the bottom of the frames and direct it upward through the bundles of tubes discharging the warmed air to the atmosphere. The tubes are internally fed with exhaust steam from the steam turbine. The steam turbine exhaust is transported in steam ducts 13 to 17 feet in diameter. These very large ducts distribute steam to increasingly smaller headers and eventually to tubes of approximately 1-inch diameter. The ACC must be located close to the steam turbine because of the expense of the large steam ducts both in terms of capital and operating costs.

The ACC is composed of multiple “cells”, each cell consisting of a single fan and many tubes over which the fan-forced air flows. The majority of ACC designs utilize fans of approximately 32 feet diameter. With this size, this installation could require anywhere from 30 to 45 “cells”.

The ACC is a simple device requiring no support equipment other than the electric power supply which is not conceptually different than that required for the wet cooling tower system, although more than double in power requirement. Because no cooling water is needed, there are several pieces of equipment that can be eliminated when using ACC. Cooling water supply piping, storage tanks, on-site chemical treatment equipment, and waste discharge piping are unnecessary with an air-cooled system. A schematic of an ACC is shown in **Soil & Water Resources Appendix Figure 3**. Note that the wind barrier surrounding the coils is not shown in the diagram. The ACC visually looks like a large box on narrow columns, the box being the wind barrier that surrounds the cells and extends from approximately 35 ft from the ground to 85 ft above the ground.

Soil & Water Resources Appendix Figure 3
Diagram of Direct Dry Cooling System



As in the case of evaporative cooling, it is possible to cool the gas turbine inlet cooling system using a radiator for the ultimate heat sink rather than the evaporative (cooling tower) system. Diagrammatically it would look similar to the above sketch except refrigerant rather that steam is condenser in the cooling coils.

Hybrid cooling is an option considered for this location by this study. The driving situation in this case is that some volume of non-potable water, including irrigation return and treated wastewater, could be made available. The AFC indicates that there is not enough to supply all 3300 AFY of cooling requirements, but as indicated above, at least 1100 AFY may be available from the most limited alternative source of water supply, from City of Blythe's WWTP. Therefore, this study includes a hybrid cooling system where 2/3 of the cooling requirements might be provided by ACC, and 1/3 by available alternative water. There are many variations of design of hybrid cooling that might perform the cooling function in this situation. All have tradeoffs related to economics and operating regime (base-load or peaking, 12 month or seasonal, etc.).

3.2 STUDY PROCESS

This Water Supply and Cooling Options Study may not necessarily use the exact economic factors and other criteria that an owner would use in designing his power plant. However, many studies, including the EPRI/CEC study and recent multiple studies done by applicants for CEC plant authorizations as well as CEC staff and support organizations, provide data/information that leads us to conclude that the selections made will not be materially different than those that will be made in an optimized design by the actual owner of a facility.

In an ACC or hybrid system, the layout of the plant needs to include locating the ACC near the steam turbine. This is because the steam duct from the turbine to the ACC is expensive and a source of pressure loss and thus efficiency loss. In order to minimize the loss it is usual to arrange the power plant so that these two devices are close to each other. The wind also affects plant layout. ACC performance and reliability is particularly sensitive to wind direction, and needs to be located with consideration to “wind storms” as well as prevailing wind. However, at this site the necessity of changing the plant layout should have minimal/moderate consequences, as the available space is very flexible as well as large. In AFC Appendix 6.0, the applicant includes the cost of new engineering/design for a plant with ACC. This is apparently based on the premise that the evaporative cooling tower design is “standard” and any other design will cost additional.

For this study the assistance of GEA Power Cooling Systems, and Hamon is specifically recognized and appreciated. These are major suppliers of both evaporative and dry condenser cooling equipment and systems. They have provided estimates of cooling system performance, cost, auxiliary (parasitic) power requirements, size and arrangement, for ACC and hybrid designs.

3.3 INFORMATION USED

The technical information needed for a study of this type includes basic cooling system design, cost information, and other application information such as structural, noise, and performance data. This type of information for ACC and evaporative cooling tower systems has been developed for many facilities that the Energy Commission has evaluated over the last several years. This category of information includes Palomar Energy Project, Potrero, Cosumnes, Morro Bay, Three Mountain Power Project, and Tesla power projects. This background of information is one of the sources used in this evaluation.

A major study was prepared in February of 2002, by EPRI (the Electric Power Research Institute) and the California Energy Commission, on the subject of alternate cooling methods applicable to power plants in California. This provides a substantial source of useful information in the evaluation of alternate cooling methods in major California climatic areas, and was used here as well.

Useful weather information for the project site was obtained from data recorded at the Blythe Airport, and published by the Western Regional Climate Center or WRCC. This is associated with the Desert Research Institute and administered by the National Oceanic and Atmospheric Administration.

Some relevant steam turbine detailed thermodynamic information was obtained from the AFC, specifically Figure 2.0-6 (4 sheets). The AFC at 2.2.4 calls these diagrams "… typical operating conditions and performance". Unfortunately, there is no heat balance for full load <u>with auxiliary firing</u> for higher ambient temperatures; the nearest is Figure 2.0-6A for 95 °F ambient temperature, with an evaporative inlet cooling system in service, but <u>without auxiliary firing</u>. In fact, the "rise" in temperature across the duct burner is a negative number of 13 °F; which is not possible. Analysis of the maximum water consumption provided by response to Data Requests 145 & 146 leads to the conclusion that the applicant intends to actually use auxiliary firing to achieve maximum summer load, but this is simply not reflected in the heat balances.

Staff has reviewed and utilized to a significant extent in this Water Supply and Cooling Options Study the cost information as provided by the applicant in its study of cooling options, AFC Appendix 6.0.

3.4 DESIGN CRITERIA/ECONOMIC OPTIMIZATION

Cooling system design criteria are substantially affected by the available water supply. When low cost water is available, the cost of ACC is generally greater than the cost of evaporative cooling both in terms of capital cost and operating cost. Because of the higher ACC cost, the normal process of optimizing economics results in a system that causes a higher steam turbine back pressure for the ACC than for evaporative cooling. One consequence of ACC selection is a reduction in the ultimate capacity of the steam turbine at higher ambient temperatures. The amount of reduced capacity of the steam turbine is a function of balancing the greater capital cost of the ACC in relation to the lost revenue of the lower peak capability on the few high ambient temperature days. The final selection of ACC size varies with the applicant's view of future power prices during peak conditions and the applicant's overall project-specific economic objectives. This is an important issue since only the applicant can perform the final optimization of plant design in compliance with its specific project economic factors and belief in future power sales. However, because many California power plants use similar sized gas fueled combined cycle plants, it is possible for this study to achieve reasonably accurate results, typical of a feasibility study.

Other than economics, the most important variables in determining the cost and performance of cooling alternatives at this location will be the criteria used for noise and visual impact. For that reason an evaluation of both of these factors are necessary in this evaluation. The proximity of the Blythe Airport means that the thermal plume and the vapor plume from the power plant are factors that need to be analyzed.

3.5 COOLING TOWER EQUIPMENT SIZE

<u>Evaporative</u>

The proposed cooling tower as designed consists of 8 cells and is 52 feet by 472 feet ground surface (footprint) (AFC Appendix 6.0 Alternatives). Height of the cooling tower is given as several different values in varying places in the AFC, but Appendix 6.0 specifies "approximately 41 ft high".. The footprint area of the above cooling tower is 24,544 ft^2; the volume is 1.006 million cubic feet.

ACC

This study concludes that the most likely ACC design, when accomplished by the applicant using its own economics and other criteria, would likely use 45 “cells.” These would be configured in a 9 cell by 5 cell array. Therefore the size of the ACC would be approximately 350 ft by 200 ft, or 70,000 ft^2 (AFC Appendix 6.0 specifies 380 ft by 190 ft, with a height of 117 ft). The 17 ft diameter main steam duct would achieve an upper height of 115 ft above ground level (Appendix 6.0 specifies 20 ft diameter steam duct). The volume of the main structure would be approximately 7.0 million cubic feet. **Soil & Water Resources Appendix Figure 4** (located at the end of this appendix) shows a modified BEP II arrangement accommodating dry cooling.

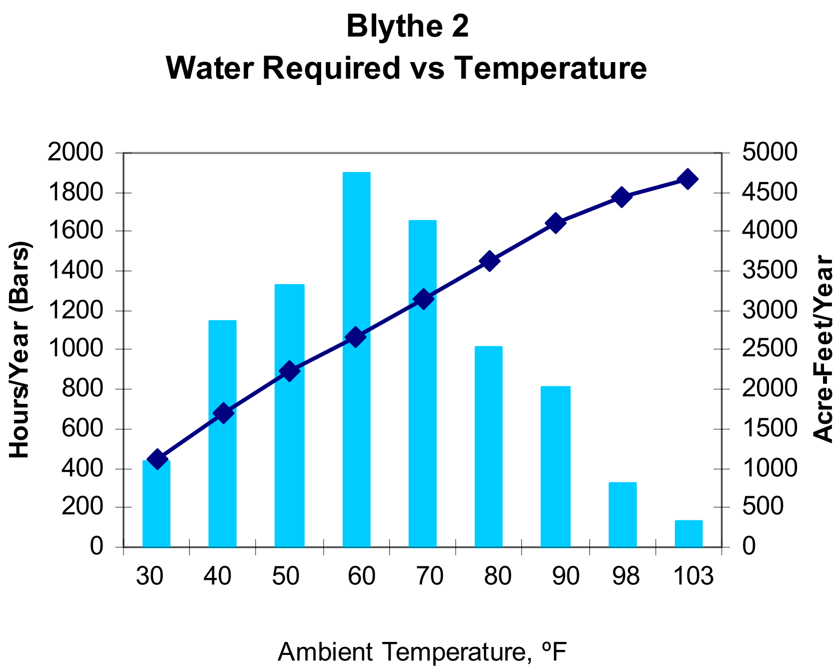
Hybrid

The Hybrid option would optimize somewhat differently since the cost of the evaporative portion of the system would be a comparatively low cost. This study concludes that 30 cells of ACC would be used, along with a single-cell evaporative cooling tower. This would require 2 areas; one of ~255 by 196 ft for ACC, and one of 42 ft square for the evaporative cooler; 51,744 ft^2 total area.

3.6 EVAPORATIVE COOLING WATER USE AS A FUNCTION OF AIR TEMPERATURE

In order to understand the relationship of BEP II water demands for cooling as a function of air temperature, staff has prepared an analysis to illustrate the increase in cooling water required using wet tower technology as temperature increases. The temperature history of the plant, using Desert Research Institute data, has been parsed into 10 ºF “buckets”. Each bucket is represented by its center. Thus, as an example of reading the chart, the bar chart for 50 ºF indicates that temperatures from 45 to 55 ºF are reached about 1300 hours each “typical” year. At this temperature the plant as proposed would consume approximately 2200 AFY, reading off the continuous dark line. Thus, if only 2200 AFY water were available, the plant could operate (400 + 1100 + 1300) 2,800 hours per year out of 8,760 hours total, until other cooling was required.

Soil & Water Resources Appendix Figure 5



3.7 COOLING TOWER CAPITAL & OPERATING COSTS

Capital Cost

The evaporative cooling system as proposed requires the cooling tower, a condenser, supporting storage tanks, the well system, chemical controls, and the means of handling the cooling tower blowdown; the brine concentrator and evaporation pond. By comparison, the ACC requires none of these supporting systems, although the complete water system for process water is still required. The process water system consumes approximately 1% of the requirements of the evaporation cooling system. The hybrid system would handle about 1/3 of the water that the full evaporative system requires, thus the supporting systems, while similar to the evaporative system, would cost somewhat less.

In preparing estimates of the considered cooling options, comparison is made with the applicant's similar consideration in Appendix 6.0 of the AFC. Cooling, or a heat sink, is required in two systems of the power plant; the steam turbine condenser and the gas turbine inlet cooling system (GTIC). For purposes of this study staff considered the steam turbine condenser cooling requirements. In Appendix 6.0 the applicant used as its base design, evaporative cooling for both the gas turbine inlet cooling system and the steam turbine condenser. In the AFC Supplement, the applicant assumes a mechanical chiller system for the GTIC which then transfers heat to a cooling tower specifically for the inlet cooling system, separate from the steam turbine condenser cooling system. Then, in postulating a dry or ACC for comparison purposes, the applicant assumed the heat sink for the gas turbine inlet cooling system would also use a radiator for the ultimate heat sink, which is essentially the same as the ACC for the steam turbine condenser. Therefore the values the applicant reaches vary somewhat from the staff values.

Estimates for each of the considered options are summarized in **Soil and Water Resources Appendix Table 5** below. The costs are study level estimates only, more suitable for comparison rather than as absolute values.

Soil and Water Resources Appendix Table 5
Estimated Capital Costs for Cooling Options ($ millions)

	Evaporative System		Dry ACC System		Hybrid
	Applicant **	Staff	Applicant ***	Staff	Staff
Condenser	2.0	included	0	included	included
Cooling Tower	3.0	“	0	“	“
Circ Water Pumps	0.6	“	0	“	“
Condensate Pumps	0.4	“	Not Included*	“	“
ACC Purchase			23.5	18.0	14.0
Construction	1.2		9.4	14.0	13.0
Subtotal	**7.2**	**8.0**	**32.9**	**32.0**	**27.0**
Evaporation Ponds	3.2	2.5	1.2	0	1
Water Treat Equip/Brine Concentrator	7.5	5.5	3.0	2.0	2.5
Added Engineering.	0.0		0.5	0.5	.5
Change “Standard” plant design	0.0	0.0	1.5	0.0	0.0
Well Pump	0.6	1.0	0	0.5	0.8
Subtotal	**11.3**	**9.0**	**6.2**	**3.0**	**4.8**
Constructed Sum	**18.5**	**17.0**	**39.1**	**35.0**	**31.8**
Capital Cost in Excess of Evap. Cooling	Base	Base	+ 20.6	+ 18.0	+ 14.8
Capacity Cost, $/kw			39.6	34.6	28.5

* Not evident why condensate pumps are not included here. They should be essentially same with either option. Not significant.

** Option includes gas turbine inlet air cooling accomplished by cooling tower for all cooling, per Appendix 6.0.

*** Option includes gas turbine inlet cooling using mechanical chiller with an air cooled heat sink – another form of air cooled condenser.

The Estimated Capital Costs for Cooling Options as summarized above in **Soil & Water Resources Appendix Table 5** contribute to the analysis of total alternative costs as later summarized in **Soils & Water Resources Appendix Table 7**. For comparison purposes, Sutter Energy Center is in an area where 1% highest temperature is 101 ºF, compared to Blythe at 112 ºF. Sutter uses a 30 cell ACC, and is reported to have incurred an increase in capital plant costs of $10 million (Fahey 2003). Staff anticipates BEP II would use a 45 cell ACC resulting in an estimated increase in capital plant costs of about $18 million. The total capital cost of the BEP II plant is estimated to be $250 Million per AFC Section 1.5.

Operating Cost

The operating cost of the evaporative system for steam turbine condenser and mechanical chiller with evaporative cooling tower heat sink, which is now the proposed design, is considered the “baseline,” and any changes resulting from selection of the options are evaluated.

Soil and Water Resources Appendix Table 6
Estimated Operating Costs for Cooling Options ($ millions)

	Evaporative System		Dry ACC System		Hybrid
	Applicant	Staff	Applicant	Staff	Staff
Parasitic	Power				
Fans	8 of 160 hp	8 of 170 hp	50of 164 hp	45of 200 hp	31of 200 hp
Fan energy, kwh / yr	5.6 million	7.1 million	35.6 million	37.8 million	26.0 million
Circulating Water Pumps	2 of 1100 hp	2 of 800 hp	N/A	N/A	1 of 400 hp
Pump energy, kwh / yr	13.6 million	9.9 million	0	0	4.7 million
Water Well Pumps	150 hp	150 hp	0	0	100 hp
Pump energy, kwh / yr	1.1 million	1.0 million	0	0	0.8 million
Wastewater Treatment	1.2 MW	1.2 MW	0.24 MW	0.24 MW	Included
Energy, kwh/yr	10.8 million	10.0 million	2.2 million	2.2 million	1.0 million
Subtotal,kwh/yr	31.1 million	28.0 million	37.8 million	40.0 million	32.5 million
Gas Turbine Inlet Cooling kwh/yr	21.6 million	0.0	39.2 million	0.0	0.0
Energy Sum kwh/yr	52.7 million	28.0 million	77.0 million	49.9 million	32.5 million
Value @ 3 ¢/kwh, M $/yr	1.581	0.840	2.310	1.497	0.975
Energy Addition for ACC, M$/yr			0.729	0.657	0.135
Cost of Energy, $/kwh			0.00017	0.00015	.00003
Other	Factors				
Chemical Costs	$350,000/yr	$300,000/yr	$50,000/yr	$20,000/yr	$120,000/yr
Other O&M			Differences	are trivial	

Since the AFC Appendix 6.0 uses both gas turbine inlet cooling and main condenser cooling, and the staff study uses only main condenser cooling, the results are in close agreement. In any case, the differential energy consumption is very small compared to the total cost of generation of electricity. The Estimated Operating Costs for Cooling Options as summarized above in **Soil & Water Resources Appendix Table 6** contribute to the analysis of total alternative costs as later summarized in **Soils & Water Resources Appendix Table 7**. The total annual BEP II operating costs are estimated at $8 Million/yr for O&M & $175 Million/yr for fuel, totaling $183 Million/yr) per AFC Section 1.5.

3.8 INCOME OR PEAK POWER PENALTY

The cost of providing the additional auxiliary (parasitic) power for the ACC or hybrid option is expressed above in operating costs. However, there are other costs of selecting either of the options compared to evaporative cooling.

- The greater consumption of auxiliary power reduces the peak load capability of the plant, thus potentially reducing capacity payments.
- Typical economically designed ACC or hybrid systems will result in higher steam turbine back pressure – and lower capacity - during hot weather periods when the potential income is typically greatest.

The parasitic or auxiliary power that is used for cooling the steam turbine condenser is unavailable for delivery to the grid. The cost of generating that power has been estimated based on typical power values in California over the past year, considering a likely replacement cost averaging$30 per MWH. However, the revenue per unit of electric power will typically be greatest during the hot weather, which is when the auxiliary power requirement is greatest. The higher auxiliary load in essence creates a "smaller" power plant.
Another typically greater source of peak power loss is the reduction in power capability (or plant capacity) during hot weather. Since either the ACC or the hybrid has a greater capital cost than the evaporative system, optimizing economics will result in poorer steam turbine performance and lower peak power capability. This is particularly acute on hotter weather days as the amount of loss increases.

These two sources of income reduction (parasitic power and plant capacity) are difficult to evaluate. Accuracy would require knowledge of either the applicant's power sales arrangements, or if power is to be sold at market rates, knowledge of future power prices. These data are neither available nor accurately predictable at this time. As a general guideline, the CEC/EPRI study evaluated these losses for 500 MW nominal power plants at various locations using several assumptions, and concluded that the most likely losses would be in the range of $0.8 to $2 million per year. It might be expected that this plant would be on the higher end of this cost range as it is located in a temperature extreme location. Therefore, staff has evaluated the effect of lost power generation within expected best to worst case scenarios assuming power values ranging from $30 to $60 per MWH as included in **Soil & Water Resources Appendix Table 7** below.

4. COST COMPARISON AND ENGINEERING MEASURES FOR WATER CONSERVATION

An economic summary of the proposed project and cooling and water supply alternatives is presented in **Soil and Water Resources Appendix Table 7**. This analysis serves to combine the water supply cost elements developed in Section 3 and cooling cost elements developed in Section 4 of this Appendix A, and provide a bottom line equivalent basis for cost comparison of the respective alternatives with the proposed project.

Soil and Water Resources Appendix Table 7
Economic Summary of Alternatives & the Proposed Project (Interest Rate of 7%)

Cost Component	Proposed Project Colorado River Groundwater with Wet Cooling	Alt. 1 Reclaimed Water from City of Blythe's WWTP with Wet Cooling	Alt. 2 Irrig. Return Water from PVID with Wet Cooling	Alt. 3 Irrig. Return Water from PVID with Hybrid Cooling	Alt. 4 Dry Cooling
		4.5 mi. of 18" @ $180/lf	1.5 mi. of 16" @ $165/lf	1.5 mi of 10" @ $120/lf	Use BEP1 Water
Water Pipeline & Well/Pump Station (Table 4)	$720,000	$5,676,000	$2,232,000	$1,620,000	$0
BEP II Water Treatment System (AFC App. 6)	$7,500,000	$9,500,000	$10,500,000	$3,000,000	**$1,500,000**
Wet Cooling Tower	$8,000,000	$8,000,000	$8,000,000		
Hybrid Cooling Tower				$27,000,000	
Dry Cooling Tower					$32,000,000
Evaporation Ponds (AFC App. 6)	$3,200,000	**$3,200,000**	**$3,200,000**	$1,200,000	$0
	786 acres @ $3250/acre				
WCOP Program Fallowing Initial Cost	$2,555,000	**$0**	**$0**	$0	$0
Subtotal - Pres. Value of Capital Costs	**$21,975,000**	**$26,376,000**	**$23,932,000**	**$32,820,000**	**$33,500,000**
Annual Costs					
Annual Water Pumping O&M & Energy	$191,000	$222,000	$199,000	$143,000	$0
Annual BEP II Water Treatment Operations	10,816 MWH x $30/MWH				
Energy	$325,000	$385,000	$475,000	$110,000	$40,000
Chemicals	$350,000	$400,000	$450,000	$120,000	$20,000
Parts & Maintenance	$100,000	$110,000	$120,000	$40,000	$20,000
Annual BEP II Water Treatment Operations	$775,000	$895,000	$1,045,000	$270,000	$80,000
	13,655 MWH x $30/MWH				
Circulating Water Pump Energy	$410,000	$410,000	$410,000	$140,000	$0
	5,561 MWH x $30/MWH				
Cooling Tower Fan Energy	$167,000	$167,000	$167,000	$56,000	35,627 MWH x $30/MWH
Air Cooled Condensor Energy				$700,000	$1,069,000
	786 acres x $500/acre				
WCOP Program Fallowing Annual Cost	$393,000				
		3,262 AF x $60/AF	3,262 AF x $85/AF	1,100 AF x $85/AF	20 AF x $85/AF
Annual Water Purchase Cost		$196,000	$277,000	$94,000	$1,700
Subtotal - All Annual Costs	**$1,936,000**	**$1,890,000**	**$2,098,000**	**$1,403,000**	**$1,150,700**
PV of Annual Costs (2003 $, 7%, 30 Years)	**$25,705,577**	**$25,094,804**	**$27,856,560**	**$18,628,577**	**$15,278,620**
	Out-of-Pocket Costs before Considering Lost Power Revenues				
PV of All Costs (2003 $, 7%, 30 Years)	**$47,680,577**	**$51,470,804**	**$51,788,560**	**$51,448,577**	**$48,778,620**

Avg. Annual Rate of Total Costs	**$3,591,034**	**$3,876,493**	**$3,900,424**	**$3,874,818**	**$3,673,732**
Incremental Power Prod. Cost ($/KWH)	**$0.00117**	**$0.00126**	**$0.00127**	**$0.00126**	**$0.00120**
	Out-of-Pocket Costs with Effect of Lost Power Revenues - Best Case @ $30/MWH				
Est. Ann. Loss of Pwr. Rev's @ $30/MWH	$0	$0	$0	$1,200,000	$1,840,000
Pres. Value of Lost Power	$0	$0	$0	$15,933,209	$24,430,920
PV of All Costs & Lost Power Revenues	**$47,680,577**	**$51,470,804**	**$51,788,560**	**$67,381,786**	**$73,209,540**
Avg. Ann. Rate of Costs w/ Lost Power	**$3,591,034**	**$3,876,493**	**$3,900,424**	**$5,074,818**	**$5,513,732**
Incremental Power Prod. Cost ($/KWH)	**$0.00117**	**$0.00126**	**$0.00127**	**$0.00166**	**$0.00180**
	Out-of-Pocket Costs with Effect of Lost Power Revenues - Worst Case @ $60/MWH				
Est. Ann. Loss of Pwr. Rev's @ $60/MWH	$0	$0	$0	$2,400,000	$3,680,000
Pres. Value of Lost Power	$0	$0	$0	$31,866,418	$48,861,841
PV of All Costs & Lost Power Revenues	**$47,680,577**	**$51,470,804**	**$51,788,560**	**$83,314,994**	**$97,640,460**
Avg. Ann. Rate of Costs w/ Lost Power	**$3,591,034**	**$3,876,493**	**$3,900,424**	**$6,274,818**	**$7,353,732**
Incremental Power Prod. Cost ($/KWH)	**$0.00117**	**$0.00126**	**$0.00127**	**$0.00205**	**$0.00240**

1) Avg. Annual Generation is estimated at 3,066,000 MWH/yr assuming a Capacity Factor of 70% x 500 MW x 8,760 Hours/yr;

2) Annual lost power generation associated with Alt. 5 - Dry Cooling is estimated to average 2% of 3,066,000 MWH/yr = 61,320 MWH/yr;

3) Annual lost power generation associated with Alt. 4 - Hybrid Cooling (2/3 Dry, 1/3 Wet) is estimated to average about 40,000 MWH/yr

4) Annual Loss of Power Revenues or Lost Power associated with Hybrid & Dry Cooling is due to a reduction in operating capacity at high air temperatures, coincident with peak power production periods;

5) Avg. annual power value is assumed to be $30/MWH;

6) PV is the Present Value of cost over a 30-year period using 7% as the time value of money.

Based on the preliminary cost comparison as shown in **Soil & Water Resources Appendix Table 7**, and before accounting for lost power generation due to reduced capacity with hybrid or dry cooling, all alternatives are comparable in cost. As Table 7 shows, even after accounting for lost power generation, the incremental effect on the cost of power production is only about .0006 to .0012 cents per KWH higher (assuming power values ranging from $30 - $60 per MWH) to implement dry cooling compared to the proposed project. Neither of these are considered significant effects on project economics or on the owner's ability to market power.

While Dry Cooling would require an additional capital investment of about $12 million over the capital cost of the proposed project attributable to the larger cooling tower, annual BEP II O&M costs are about $800,000 less for Dry Cooling compared to the proposed project attributable primarily to water pumping, treatment and purchase cost savings. Dry cooling would accomplish the highest conservation of fresh water, reducing average annual water use from 3,262 AFY to about 40 AFY. No new water supply infrastructure by way of wells, pumps or off-site pipelines would be needed, as the minimal 40 AFY needed to support dry cooling could be made available using the existing BEP1 infrastructure. Data in this table is intended to provide an equivalent basis for comparing the proposed project with alternative water supply and cooling methods.

Other Water Conservation Measures Considered

Wastewater Recovery Option - ZLD

Although the water conservation potential of implementing a complete Zero Liquid Discharge to Solid (ZLDS) system at BEP II is not significant compared to the proposed Zero Liquid Discharge of brine to evaporation ponds (ZLDB), there may be other environmental concerns that would lead to eliminating the two 8-acre evaporation ponds and implementation of a complete ZLDS system. The proposed project already includes a brine concentrator for treatment and recovery of plant wastewater. The impact of eliminating the evaporation ponds would be an additional cost for ZLDS brine drying of about $5 million less a savings of about $3.2 million for the evaporation ponds, for a net increase in project cost of about $1.8 million. The ZLDS may cause minor noise and visual impacts, which would be considered insignificant. Water savings of about 100 acre-feet per year could be achieved, reducing the average annual demand from 3,262 AFY to about 3,162 AFY. Staff does not recommend implementation of a complete ZLD system on the merits of water conservation alone. Instead, other environmental issues, such as potential effects to wildlife or other considerations may require its use as mitigation for significant impacts.

5 ENVIRONMENTAL AND ENGINEERING ANALYSIS

5.1 AIR QUALITY

Introduction

This discussion addresses the changes in emissions and air quality effects of: (1) selecting a degraded water supply and construction of the water conveyance pipeline, and (2) construction and operation of cooling technologies that would reduce water loss to evaporation and drift. The cooling options would also reduce the net power output of the plant because of increased parasitic power requirements over the proposed evaporative cooling system. This discussion assesses the economic “replacement cost” of the lost power, and therefore, assumes that the power plant would not need to increase emissions because of a change in the cooling technology.

PVID’s Irrigation Return Water Supply Option

Construction of a water conveyance for the irrigation return water supply option would generate offsite emissions from construction equipment. The nature of these emissions would be similar to those identified for the equipment used onsite, but of a much smaller quantity. Depending on the width of the right-of-way needed to construct the 1.5-mile line, about 15 additional acres would be temporarily disturbed along the conveyance route. Although emissions from construction equipment would be short-term, with the additional linear facility needed for this water supply option, the construction emissions would be slightly greater, and the activities would extend for a slightly longer duration, than those of the proposed project. These emissions would be reduced by Conditions of Certification AQ-SC1 through AQ-SC4 in the Air Quality section of the PSA.
Changing the water supply could change operational emissions at the power plant if the total dissolved solids (TDS) content of the cooling water changes substantially. Cooling tower drift emissions (PM_{10}) were quantified in the AFC, and the supplement for inlet

chilling, on the basis of a range of anticipated TDS from 4,000 mg/l (or ppm by weight) to 8,190 mg/l. When preparing the Air Quality section of this staff assessment, staff assumed that the cooling water used in either the cooling tower or the inlet chilling system could have TDS up to 8,190 mg/l. Staff's approach overestimates the PM_{10} emissions from cooling equipment as long as the cooling water is not cycled and concentrated through the cooling system to cause TDS over 8,190 mg/l. This issue would be addressed by a Condition of Certification (AQ-40) in the Air Quality section of the PSA.

Irrigation return water would have higher TDS than the groundwater that would be used under the project proposal. Compared to the proposed project groundwater, which has been considered to have a TDS of 1,010 mg/l, irrigation return water is considered to have an average TDS of 1,630 mg/l. Because the irrigation return water supply would have TDS levels well below the 8,190 mg/l used in the Air Quality assessment, the cooling tower drift emissions would not be greater than those characterized in the staff assessment.

Operational emissions along the irrigation return water pipeline would only occur if internal combustion engines were used for pumping or emergency power. Because pumping irrigation return water to the power plant site would be accomplished with an electric pump system, no offsite operational emissions are expected.

Dry Cooling

Construction of a dry cooling system would cause a minor increase in the overall construction emissions to accommodate the larger footprint of the system (about one additional acre) compared to the evaporative cooling system proposed in the AFC. In the context of the 76 acres anticipated to be disturbed during on-site construction, the dry cooling option would result in only a minor change to the overall anticipated construction emissions.

Dry cooling systems eliminate cooling water contact with the ambient air, which eliminates potential emissions of cooling water droplets containing drift (PM_{10}). This option would eliminate all operational emissions (15.7 tons per year PM_{10}) from the proposed cooling tower.

Hybrid Cooling

Construction of a hybrid cooling option would involve an air cooled condenser (ACC) and an evaporative cooling tower of reduced footprint. The total area disturbed during construction of this option would be less than one additional acre, which would not substantially change the air quality impacts occurring during construction.

This hybrid cooling system would substantially reduce the quantity of cooling water that contacts the ambient air, which would reduce emissions of cooling tower drift (PM_{10}). Because it would handle approximately one-third of the water that the full evaporative cooling system would require, this option would eliminate approximately two-thirds of the operational PM_{10} emissions from the proposed cooling tower.

Conclusion

The irrigation return water supply option would increase construction emissions by requiring construction of an additional offsite linear facility for water conveyance. Operational emissions from cooling tower drift (PM_{10}) would not change from those shown in the staff assessment because the TDS of the water has been sufficiently overestimated (at a maximum of 8,190 mg/l) in the staff assessment.

Construction of the optional dry cooling or hybrid cooling systems would have similar air quality effects as construction of the cooling system proposed in the AFC. Eliminating or reducing the project's reliance on wet cooling would eliminate or reduce the drift emissions (PM_{10}) from the proposed cooling tower, which are a notable portion (about twenty percent) of the total proposed operational PM_{10} emissions of the plant. Dry cooling would entirely eliminate the cooling tower drift emissions.

The applicant would be required to comply with the Energy Commission Conditions of Certification regarding construction emissions to minimize impacts related to construction of the optional pipeline. With these measures, no substantial change in air quality impacts would occur.

5.2 BIOLOGICAL RESOURCES

Introduction

This section examines the potential impacts of alternative cooling systems to biological resources at the proposed BEP II site and surrounding areas. The use of degraded water is evaluated in comparison to the use of water from freshwater ecosystems. The use of dry and hybrid cooling was evaluated on the balance of benefits and impacts to freshwater ecosystems versus benefits and impacts to terrestrial species and their habitat. This analysis focuses on impacts to state and federally listed species, fully protected species, species of special concern, wetlands, and other areas of critical biological concern.

In order to determine the ecological significance of project impacts, Staff relies primarily upon standards and guidelines established by the Federal and State Endangered Species Acts, the California Environmental Quality Act (CEQA), the Migratory Bird Treaty Act, items found in the Warren-Alquist Act, and recent Presidential (executive) orders relevant to biological resources (e.g., Executive Order 13112 for management of invasive species). Staff must determine significance based on whether populations of endangered, threatened, protected, and sensitive species or biotic communities will be adversely affected by BEP II. Significant impacts are those which affect a species' population size, geographic range, habitat, nesting success, and migration, or those that diminish, fragment, contaminate, or otherwise threaten biotic communities. The Fish and Game Code and other state and local regulations also help staff assess impacts. The above regulations direct Applicants to avoid and mitigate for the loss of habitat for sensitive species and to obtain permits for incidental take of protected species.

PVID's Irrigation Return Water Supply Option

The water borne contaminants are a biological concern because they impact the long-term survival of fish and wildlife populations. The electric conductivity, an indicator for salinity, in PVID canal water is estimated at over 2,000 ppm and total dissolved solids is over 1,700 mg/l (PVID 2003). The selenium is unmeasured, but investigations into selenium levels in Colorado River and its immediate drain water found selenium levels exceed the guidelines for protection of fish and wildlife resources (Radtke et al. 1988). It is likely that selenium levels in Rannells drain are high enough to be of biological concern. When cycled through the proposed project's brine concentrator and then discharged into the evaporation ponds, the PVID irrigation return water would expose birds and bats to levels of salinity and selenium that are unhealthy. This impact could be eliminated by the installation of a zero liquid discharge brine distiller in lieu of using evaporation ponds as part of the design.

The construction of a water supply pipeline would create disturbance in areas with burrowing owls, and potentially desert tortoise habitat. Additional conditions of certification in order to ensure impacts remained less than significant would be necessary. The cost to mitigate the water pipeline would be around $1,200 per acre of disturbance in desert tortoise habitat, and on-site mitigation per owl pair (or resident individual) including reconstruction of burrows and monitoring of their success, and permanent habitat protection where needed would be required.

In order to connect PVID irrigation system to the power plant site, the analysis proposes two pipeline routes. PVID route A begins at Rannells Drain near 12th Ave. and travels north along Rannells Drain to Riverside Ave. Rannells Drain Canal may contain suitable nesting habitat for special status bird species, including vermilion flycatcher (Species of Concern). During the proceedings for Blythe Energy Project (BEP I)(99-AFC-8) the natural gas line route was changed to avoid this exact section of Rannells Drain (between 10th Avenue and Riverside Avenue) to reduce impacts to biological resources (Harvey 2000). PVID Route B also begins on Rannells Drain, but immediately departs from it and continues along Hobsonway. PVID route B would be preferred to PVID route A because it reduces potential impacts to the riparian vegetation in the drain.

Dry Cooling

While there is a minor concern that the withdrawal of freshwater could result in impacts to Colorado River and the species that depend on it, the largest concern Biological Resources staff has with the proposed evaporative cooling method is the discharge of wastewater that is high in salts and selenium. Dry cooling would eliminate the need for a 6.48-acre evaporation pond (BEP II 2002g, Data Response 59) and would reduce exposure risk of birds and bats to the water borne contaminants predicted in the proposed project.

The land area required for dry cooling (70,000 ft^2 or 1.6 acres) would be smaller than for the evaporative cooling proposed by the applicant (24,544 ft^2 or 0.5 acres plus a 6.48 acre evaporation pond). The loss of desert tortoise habitat was already fully mitigated by the adjacent power plant's use of the site for the disposal of fill. Thus, so long as the dry cooling could be contained within the existing fence line, no additional impacts to desert tortoise habitat would be expected to result from dry cooling.

Hybrid Cooling

Hybrid cooling would still require an open discharge into evaporation pond which is a concern for Biological Resources staff as discussed above. The hybrid system would expose birds and bats to levels of salt and selenium that are unhealthy. This impact could be eliminated by the installation of a zero liquid discharge brine distiller in lieu of using evaporation ponds as part of the design.

The land area required for hybrid cooling (51,744 ft^2 total area or 1.2 acres plus an evaporation pond that is less than 6.48 acres in size) would be equivalent or smaller than for the evaporative cooling proposed by the applicant (24,544 ft^2 or 0.5 acres plus an 6.48 acre evaporation pond). The loss of desert tortoise habitat was already fully mitigated by the adjacent power plant's use of the site for the disposal of fill. Thus, so long as the dry cooling could be contained within the existing fence line, no additional impacts to desert tortoise habitat would be expected to result from dry cooling.

Conclusion

Dry cooling or hybrid cooling have no biological advantage over the use of evaporative cooling if the waste water is processed using a zero liquid discharge brine distiller instead of evaporation ponds. The use of the proposed evaporative cooling, PVID return water or hybrid cooling with discharges to an open evaporation pond would be less preferable to dry cooling. In addition, the installation of the PVID return water pipeline is expected to increase the probability of impacts to riparian birds, desert tortoise habitat and to burrowing owls, and this is the least preferred alternative from a Biological Resources perspective.

5.3 CULTURAL RESOURCES

Introduction

In general, impacts to cultural resources are increased when ground disturbance is increased. Cultural resources evaluated as eligible to the National Register of Historic Places (NRHP) or the California Register of Historic Resources (CRHR) would require mitigation. To effectively analyze potential impacts to cultural resources, information from the appropriate California Historic Resource Information System (CHRIS) office is necessary. A record search at the CHRIS has not yet been completed for any of the alternative water supply or cooling systems.

PVID's Irrigation Return Water Supply Option

Trenches for water pipelines, construction activities, and staging areas all result in disturbance of the ground and have the potential to impact archeological deposits. Further off site study would be required, however, it is assumed that any impact could be mitigated to a less than significant level.

Dry Cooling

Even though in comparison to the proposed BEP II project, the dry cooling structure would have a larger footprint, it would not result in any additional impacts to cultural resources as long as it is within the current BEP II plant site and outside of the fenced area containing the cultural resources site.

Hybrid Cooling

As long as the water treatment facilities, pipeline and cooling facility are all within the current BEP II plant site and outside of the fenced area containing the cultural resources site, there would be no additional impact to cultural resources.

Conclusion

The PVID's Irrigation Return Water Supply Option has the greatest potential for impacts to cultural resources. If all of the components of the Dry Cooling and Hybrid Cooling options are within the current BEP II plant site and outside of the fenced area containing the cultural resources site, there would be no additional impact to cultural resources by either of these alternatives.

5.4 HAZARDOUS MATERIALS MANAGEMENT

Introduction

The BEP II is currently proposing to use ground water from on-site wells for cooling. The purpose of this analysis is to determine if there would be any additional impacts due to use of hazardous materials for the different water supply and cooling options.

PVID's Irrigation Return Water Supply Option

PVID operates a system of irrigation supply and return drainage ditches. The drainage ditches are about 10 to 20 feet deep in order to intercept groundwater about 10 feet below the ground surface (valley-wide average depth). During crop irrigation, excess water is applied to prevent salt build-up in the soil. This excess irrigation water percolates through the soil and into groundwater. Groundwater then flows to the drainage channels and is returned to the Colorado River.

The Rannells Drain runs in the vicinity of BEP II and contains intercepted shallow groundwater (after being applied for irrigation) and operational spillage from Canal B, a source of irrigation supply for the immediate area. The quality of water in the Rannells Drain is largely influenced by local agriculture activity (which degrades the drainage water quality) and Canal B irrigation spillage (which enhances the drainage water quality). As an indication of water quality in the Rannells Drain, PVID's observed TDS was 1,510 mg/l on an undisclosed date in September 2002 and 1,590 mg/l on March 14, 2003. In comparison, irrigation water diverted from the Colorado River on those dates was observed to have TDS concentrations of 552 mg/l and 728 mg/l respectively (PVID 2003d). PVID typically collects water quality data on a quarterly basis for its irrigation supply as diverted from Colorado River and on a bi-annual basis for its irrigation return flows in Rannells Drain (PVID 2003d).

Use of irrigation return water from PVID at BEP II would require construction of a 1.5 mile water supply pipeline from Rannells Drain to BEP II. The pipeline would be expected to follow one of the two alternative routes as described in Section 2.3.

Analysis of Construction and Operations Impacts

There are minor amounts of hazardous materials (fuels, solvents, lubricants, etc.) used in the construction of pumping facilities and water pipelines. Because of the small amounts, low potential for off-site migration, and/or solid form, the use of hazardous materials during the construction of any water pipeline or pumping station would not result in a significant risk to the public. Although not certain, pump motors for these types of pipelines are usually electric, thus obviating the need for fuel use at the pumps.

The drainage water from the irrigation supply and return system would most likely need to be processed and pretreated before it can be used as a cooling medium in the BEP II project. Manufacturers of cooling equipment typically specify that the cooling medium to be used meet certain criteria in order to be acceptable for use with their equipment. This is necessary to alleviate the general water quality problems of scaling, corrosion, biological growth and fouling. The pretreatment involves chemical conditioning and the type, level, frequency and intensity of the pretreatment would depend on two factors, as a minimum. The quality of the water would be one factor. The second would be the technical specifications for the cooling medium as required by the cooling equipment manufacturers. BEP II's design engineer would need to specify the type and amount of each chemical that would be required under PVID's irrigation return water supply option. It is possible that additional hazardous materials storage areas may need to be constructed, complete with berms and drainage protections, in order to accommodate the additional volumes of hazardous materials.

Dry Cooling

In a dry cooling system, fans blow air over a radiator system to remove heat from the system via convective heat transfer (instead of once-through cooling or evaporative heat transfer). The direct dry cooling system, proposed as an alternative for the BEP II is also known as an air-cooled condenser (ACC). In this system, steam from the steam turbine exhausts directly to a manifold radiator system that rejects heat to the atmosphere, condensing the steam inside the radiator. The use of the ACC could reduce by up to 96% the water used by the proposed project. Because no cooling water is needed with this option, several pieces of equipment can be eliminated including cooling water supply piping, storage tanks, on-site chemical treatment equipment, and waste discharge piping.

Analysis of Construction and Operations Impacts

Dry cooling would not use the large volumes of water used in wet or hybrid cooling systems and hence would reduce the volume of chemicals (e.g., sodium hypochlorite) needed to control algae growth within the system (particularly in the condenser tubes). Thus, hazardous materials usage would decrease. On the other hand, the larger volume of piping including seals, flanges, and valves, may result in oxygen entry into the system and therefore require an increase use in oxygen scavengers to prevent corrosion and scaling. The BEP II project is proposing to use carbohydrazide, a material of very low toxicity, as an oxygen scavenger. The increased use of carbohydrazide for a dry cooling system could be significant but would still not result in an increased risk or hazard. Thus, the overall use of hazardous materials with dry cooling would be the same or less than as with wet cooling.

Hybrid Cooling

Hybrid cooling systems combine wet and dry cooling technologies. This analysis considers a hybrid cooling system where 2/3 of the cooling requirements might be provided by ACC, and 1/3 by available non-potable water.

Analysis of Construction and Operations Impacts

The hybrid cooling alternative would use larger volumes of water than dry cooling. Therefore, the amount of hazardous materials and the risk of accidental release would be somewhat greater than with dry cooling. However, because the risk is very low with dry cooling, the difference between dry and hybrid cooling risks are not significant.

Conclusion

The construction of any of the cooling options would require very small amounts of hazardous materials. The impacts are expected to be no different from those identified for the construction of the proposed BEP II as described in the **Hazardous Materials Management** PSA Section and can be addressed by adherence to the LORS and proposed Conditions of Certification found in the Staff Assessment.

The use of water from the PVID's irrigation supply and return system in the cooling process would require the storage and use of hazardous chemicals. As a minimum, the quality of the water, cooling medium specification requirements, and applicable waste discharge standards would all influence the types of chemicals needed and their quantities for use of reclaimed water in cooling.

Staff does not consider the impacts from any of the water sources or the cooling options discussed to be significantly different, since rather minor differences in hazardous materials use would exist with any of the options. Any risks associated with chemical usage in cooling water should be adequately mitigated through compliance with the appropriate federal, state, and local requirements for hazardous materials use and adherence to the applicant's and staff's proposed conditions of certification. These proposed mitigation methods are standard for power plants licensed by the CEC and thus the overall risk due to hazardous materials is approximately the same for all proposed water sources and cooling methods.

5.5 LAND USE

Introduction

The evaluation of alternative BEP II cooling technologies for the land use technical area is primarily focused on two issues: (1) consistency with applicable land use plans, ordinances, and policies; and, (2) compatibility with existing and planned land uses.

PVID's Irrigation Return Water Supply Option

If irrigation return water is used for project cooling instead of ground water, a Water Conservation Offset Plan (WCOP) would not be implemented, and there would be no project impact on agricultural land or other land uses. Therefore conditions of certification **LAND-3**, regarding impact on Williamson Act agricultural preserve contracts, and **LAND-4**, regarding impact on agricultural land, would not be necessary.

The use of irrigation return water would not cause a change in aviation safety impact from visual and thermal plumes, and would not affect the Commission's determination as to whether the project is consistent with the Comprehensive Land Use Plan (CLUP) for the Blythe Airport.

Dry Cooling

Dry cooling would eliminate the need for 95 percent of the water necessary for project cooling using wet cooling design as proposed in the AFC. The WCOP would not be implemented and there would be no significant project impact on agricultural land or other land uses. Therefore conditions of certification **LAND-3**, regarding impact on Williamson Act agricultural preserve contracts, and **LAND-4**, regarding impact on agricultural land, would not be necessary. Regarding aviation safety, it is possible that dry cooling would eliminate any significant impact from visual plumes, but cause greater impact from thermal plumes. Final conclusions regarding the impact of visual and thermal plumes cannot be made until completion of a visual and thermal plumes study by a Commission consultant and state and federal agencies addressing aviation safety.

Hybrid Cooling

The typical hybrid cooling system would reduce water usage for plant cooling by approximately 50 percent. Therefore, the need for underground water would be lowered by the same percentage. The applicant proposes to use the WCOP to retire irrigated lands permanently or fallow lands on a rotating basis to reduce demand for agricultural irrigation in exchange for the water used by the project. If the permanent land retirement option is chosen, the WCOP may have a significant impact on agricultural land. See the Impacts subsection in the Land Use Section of this PSA for further information on the WCOP and possible impacts on agricultural land. If hybrid cooling is used, the impact on agricultural land would be 50 percent less than with the wet cooling system, there would continue to be a significant impact on agricultural land, and there would be no change in the recommended conditions of certification. Regarding aviation safety, It is possible that hybrid cooling would lower impact from visual plumes, but cause greater impact from thermal plumes. Final conclusions regarding the impact of visual and thermal plumes cannot be made until completion of a visual and thermal plumes study by a Commission consultant and state and federal agencies addressing aviation safety.

Conclusion

The alternatives to wet cooling are compatible with all LORS except for concerns about consistency with the CLUP. A Commission study by a consultant and state and federal agencies addressing aviation safety on the impacts of visual and thermal plumes produced by the project must be completed before conclusions can be reached on CLUP consistency.

Of the three alternatives studied, only adoption of the hybrid cooling system would cause a significant impact on agricultural land, and there would be no change in the recommended conditions. Use of irrigation water return supply or dry cooling would lessen impact on agricultural land to less than significant, and there would be no need for conditions protecting agricultural lands. The cooling alternatives would not affect any other land uses.

5.6 NOISE

Introduction

Following is a noise analysis of the water supply and cooling options for the BEP II project. The reason for considering these options is that the Applicant is currently proposing to use ground water from on-site wells for cooling. Based on State Water Board Policy encouraging use of recycled or degraded water over potable water for cooling, staff is evaluating (a) sources of degraded water for the BEP II facility and (b) cooling technologies that allow the volume of water to be reduced.

PVID's Irrigation Return Water Supply Option

The source of the cooling water has no direct effect on project noise levels, unless there are differences in pumping requirements that would cause installation of noise-producing pumps or motors in close proximity to sensitive receivers. It does not appear that this condition would occur, so there would be no change in project noise impacts as a result of using an alternative source of cooling water.

Dry Cooling

The evaporative cooling system proposed in the AFC includes 8 fans. The AFC Appendix 6.0 specifies the power rating of these fans at 160 horsepower each. In the ACC option there would be 45 fans of 200 horsepower each, or 50 fans of 175 horsepower each. As a result, noise levels would be increased substantially in the near field. This is relevant for occupational noise exposures, but would be managed to acceptable levels in accordance with the staff's proposed Condition of Certification **NOISE-7**.

The AFC Appendix 6.0 concludes that ACC would produce about 67 dBA at 400 feet compared to 60 dBA at 400 feet for the evaporative system. An increase of about 7 dBA in cooling system noise would be of concern to the developer because the Energy Commission staff has proposed a noise standard for the BEP II (**NOISE-6**) that would require a 2 dBA reduction in the overall power plant noise level for the proposed design. The cooling tower is considered to be one of the larger contributors to the overall power plant noise level at the nearest receptor, so reduction of cooling system noise would be a key factor in achieving the proposed noise standard. It is not known whether it would be feasible to achieve the required noise level reduction for a power plant design including the use of ACC.

ACC noise could be significantly reduced by using low-noise fans, or by installing a larger ACC that could use lower-power, quieter, fans. For example, a noise level reduction of about 10 dBA could be accomplished by using low-noise fans in the ACC, with a corresponding increase in cost of the ACC of approximately $1.2 million.

The power plant could be designed so that the ACC would be nearer the midpoint of the site. This would result in a distance to the northern boundary of 1,200 ft or more. This increased distance would reduce cooling system noise at the north plant boundary to about 57 dBA. However, this relocation would place the ACC closer to the sensitive receiver, which is located south of the proposed BEP II. Therefore the overall power plant noise level would likely be increased at the sensitive receiver.

Hybrid Cooling

A hybrid cooling system would use an intermediate number of fans as compared to the ACC and evaporative systems. The resulting noise levels would also be expected to be intermediate, so that the hybrid system would be expected to produce slightly higher noise levels (estimated by staff to be 4 dBA) than the evaporative system. As with the ACC system, the developer would have to implement noise reduction technology to ensure that the hybrid cooling system noise emissions would be consistent with the objective of reducing overall plant noise levels by about 2 dBA, as required by staff's proposed Condition of Certification **NOISE-6**. It is not known whether it would be feasible to achieve the required noise level reduction for a power plant design including the use of hybrid cooling.

The power plant could be designed so that the hybrid cooling system would be nearer the midpoint of the site. This would result in a distance to the northern boundary of 1,200 ft or more. This increased distance would reduce cooling system noise at the north plant boundary. However, this relocation would place the cooling system closer to the sensitive receiver, which is located south of the proposed BEP II. Therefore the overall power plant noise level would likely be increased at the sensitive receiver.

Conclusion

The use of alternative supplies of cooling water is not expected to have a significant effect on power plant noise levels. The use of either ACC or Hybrid cooling would increase cooling system and overall power plant noise levels. The cooling system is considered to be a major contributor to the overall power plant noise levels. Since the current proposed power plant design would require noise mitigation measures to achieve the Energy Commission staff's proposed Condition of Certification **NOISE-6**, the use of ACC or hybrid cooling would require substantial additional noise reduction, at increased cost.

5.7 PUBLIC HEALTH

Introduction

The BEP II is currently proposing to use ground water from on-site wells (Colorado River groundwater) for cooling. Based on State policy encouraging use of recycled or degraded water over potable water for cooling, staff is evaluating (a) sources of degraded water for the BEP II facility and (b) cooling technologies that allow the volume of water used to be reduced. Any public health impacts from cooling-related use of reclaimed water would result from public exposure to any toxic pollutants posing cancer and non-cancer risks. The potential for such impacts would depend on the presence of pollutants in the cooling tower drift, any subsurface contamination that may be unearthed during construction of the water conveyance and treatment facilities or exposure to fugitive dust emissions as well as heavy equipment operation during such construction.

PVID's Irrigation Return Water Supply Option

Historical and current agricultural activities may have contributed to the presence of pesticides in the irrigation return water. In addition, various events such as spills or leaks could have led to the release of other contaminants into the irrigation water. The potential release of such contaminants via cooling tower drift may pose undue human health risks.

Efforts are currently underway by staff to obtain and review available information about the quality of the irrigation return water including the presence of any contaminants. Any discussion of the potential health concerns associated with the presence of contaminants in the irrigation return water will only be feasible following review of the appropriate information. Such a discussion will therefore be presented in the Final Staff Assessment (FSA) if further analysis of this issue is necessary.

Potential risks to public health during construction of the irrigation water pipeline may be associated with fugitive dust exposure as well as exhaust from heavy equipment operation. The pipeline construction is expected to be extremely limited in scope and duration. Emissions from these construction activities would invariably be minor and therefore insignificant given the scope and duration of these activities. In addition, subsurface contamination may be encountered during the pipeline construction activities. Compliance with the LORS cited by the Applicant for the proposed BEP II project should adequately ensure that any subsurface contamination would not pose a significant health risk to the construction workers and the public.

Dry Cooling

With the elimination of water as a cooing medium in this option, no contaminants are expected to be present in the drift from the cooling towers. Consequently, dry cooling will not be detrimental to the public as a result of exposure to airborne contaminants.

Hybrid Cooling

The proposed use of hybrid cooling would result in the use of only one-third of the water needed for the proposed wet cooling system. Risks to the public from the use of the Colorado River groundwater for cooling purposes as proposed, would therefore be reduced even further. As discussed above, data pertaining to the possibility of contaminants in the PVID irrigation return water is currently being sought. A discussion on the potential risks posed by the PVID irrigation return water will be included in the FSA is so required.

Conclusion

Staff concludes that dry cooling and the use of Colorado River groundwater in hybrid cooling would not be detrimental to public health. Any conclusion related to the use of PVID’s irrigation return water as a cooling medium depends on obtaining additional water quality information which would be available in the FSA if so required.

5.8 TRAFFIC / TRANSPORTATION

Introduction

A number of degraded water supply and cooling technology options are currently under consideration for the BEP II. These options are alternatives to the BEP II cooling proposal, which would utilize ground water from on-site wells for the evaporative cooling towers. The traffic and transportation construction and operations impacts of the alternatives, which include PVID's Irrigation Return Water, Dry Cooling, and Hybrid Cooling, are discussed below.

PVID's Irrigation Return Water Supply Option

The construction of an irrigation return water supply system, including a new pipeline connecting the Blythe water treatment plant with the project, would require additional construction truck and worker traffic. Receipt of construction traffic data and impact assessment from the applicant is necessary before staff can complete the analysis of this additional traffic. The use of irrigation return water would not alter visual and thermal plumes, which are the subject of a study by a Commission consultant and state and federal agencies addressing aviation safety.

Dry Cooling

Construction of a dry cooling system would require additional construction truck and worker traffic. Receipt of construction traffic data from the applicant is necessary before staff can complete the analysis of the extent and impact of this additional traffic. Regarding aviation safety, it is possible that dry cooling would eliminate significant impact from visual plumes, but cause greater impact from thermal plumes. Final conclusions regarding the impact of visual and thermal plumes cannot be made until completion of a visual and thermal plumes study by a Commission consultant and state and federal agencies addressing aviation safety.

Hybrid Cooling

Construction of a hybrid cooling system would require additional construction truck and worker traffic. Receipt of construction traffic data from the applicant is necessary before staff can complete the analysis of the extent and impact of this additional traffic. Regarding aviation safety, It is possible that hybrid cooling would lower impact from visual plumes, but cause greater impact from thermal plumes. Final conclusions regarding the impact of visual and thermal plumes cannot be made until completion of a visual and thermal plumes study by a Commission consultant and state and federal agencies addressing aviation safety.

Conclusion

Construction of the alternative cooling systems would each require additional construction truck and worker traffic. Additionally, an irrigation return water supply system would require the construction of a new pipeline connecting the project with the water treatment plant. Staff assumes that any significant traffic impact caused by the construction of the selected cooling alternative could be adequately mitigated. However, applicant submittal of construction information and construction traffic data for the selected cooling alternative is necessary before staff can complete the analysis of the extent and impact of this alternative. A Commission study by a consultant and state and federal agencies addressing the impacts of visual and thermal plumes produced by the project, must be completed before staff can make an assessment of the cooling alternatives' impact on aviation safety.

5.9 VISUAL RESOURCES/ PLUME ANALYSIS

Introduction

This discussion addresses whether the alternative water supply option and cooling technologies would cause significant adverse visual impacts.

PVID's Irrigation Return Water Supply Option

PVID's Irrigation Return Water Supply Option would require the construction of a 1.5- to 2-mile water supply pipeline. The pipeline would follow one of two routes to the BEP II site, one along Riverside Drive and Chanslor Way and one along Hobsonway and Buck Boulevard. Construction of the pipeline would result in the temporary visibility of construction vehicles, equipment, materials, and personnel along discrete segments of roadway as construction progresses along the route. Any construction through agricultural fields to reach the roadways would be confined to existing utility easements or along the shoulder of agricultural access roads wherever possible. No new access roads would be required. The visibility of construction activities along any portion of the route would be relatively short in duration and the resulting visual impact would be adverse but not significant. Following installation of the pipeline underground within existing rights of way, the pipeline would not be visible and would not result in adverse visual impacts.

This option is not expected to significantly change the design or operation of the cooling tower as proposed by the applicant, nor would it change the design or operation of the turbine/HRSG. Therefore, this option, or any other water supply substitution option, would not be expected to change the plume frequency and size characteristics of the cooling tower as evaluated in the Visual Resources Section, which found that that there would be no significant impacts as the plume frequencies would be below staff's significance criteria threshold of 10 percent.

Dry Cooling

The dry cooling option would require the use of an Air Cooled Condenser (ACC) consisting of multiple finned heat exchange tubes mounted on a large steel framework. Fans are used to draw air in the bottom of the frames. The ACC is composed of multiple "cells," each cell consisting of a single fan and many tubes over which the fan-forced air flows. A typical fan is approximately 32 feet in diameter and an ACC for the BEP II project would require 30 to 45 cells. Visually, the ACC would look like a large box on narrow columns, the box being the wind barrier that surrounds the cells and extends from approximately 35 feet above the ground to 85 feet above the ground. As described elsewhere in this report, the most likely ACC design would use a 45-cell design and would be configured in a 9-cell by 5-cell array. The structure would be approximately 350 feet by 200 feet and 115 feet in height, which is only 15 feet shorter than the proposed HRSG stacks (at 130 feet in height).

The ACC would be visible as a large, elevated, geometric structure that would appear prominent and quite massive from foreground to middleground viewing distances along Hobsonway and I-10. The cooling structure would exhibit an industrial visual character similar to that of other existing and proposed structures at and adjacent to the site. The cooling structure would result in substantially greater visual contrast and view blockage compared to the proposed cooling tower. The resulting visual impact would be adverse and significant from KOPs 2 and 7 on Hobsonway and I-10 respectively. Effective implementation of Visual Resources Conditions of Certification VIS-2, VIS-3, and VIS-5 would be sufficient to reduce the impact of the ACC to a level that would not be significant.

This option would completely eliminate the cooling tower visible plumes and would not be expected to change the turbine/HRSG visible plumes. Therefore, this cooling option would reduce the visible plume impacts from those that were already found to be less than significant.

Hybrid Cooling

The hybrid cooling option would require a single-cell evaporative cooling tower and a 30-cell ACC. The relatively small size of the single-cell evaporative cooling structure would not result in a significant visual impact in the context of the existing and proposed power plant facilities. However, at approximately two-thirds the size of and the same height as the dry cooling ACC, the hybrid cooling ACC would be a prominently visible built feature in the landscape, measuring approximately 255 feet by 196 feet and 115 feet in height. Similar to the dry cooling ACC, the hybrid ACC would exhibit an industrial visual character similar to that of other existing and proposed structures at and adjacent to the site. The cooling structure would result in substantially greater visual contrast and view blockage compared to the proposed cooling tower. The resulting visual impact would be adverse and significant from KOPs 2 and 7 on Hobsonway and I-10 respectively. Effective implementation of Visual Resources Conditions of Certification **VIS-2**, **VIS-3**, and **VIS-5** would be sufficient to reduce the impact of the hybrid ACC to a level that would not be significant.

This option would reduce the frequency and size of the wet cooling tower plumes and would not be expected to change the turbine/HRSG visible plumes. The hybrid system will operate with the dry cooling taking most of the heat load so that the cooling tower operation would generally increase with increased load which would typically happen during duct firing and during summer daylight hours. Therefore, cooling tower operations would be expected to increase during times with lower plume formation potential and decrease during times with higher plume formation potential. Additionally, the size of the cooling tower would be reduced so the plume sizes, assuming similar design characteristics, would also be smaller than for the wet cooling only option. Therefore, this cooling option would reduce the visible plume impacts from those that were already found to be less than significant.

Conclusion

The use of PVID's irrigation return water for cooling would result in visual impacts similar to those of the proposed project since the principal component of the PVID option would be an underground pipeline that would not be visible during project operation.

Both the dry cooling and hybrid cooling options would result in potential significant visual impacts that would be greater than the proposed project because of the substantial size of the ACC that would be required for project cooling under either option. Effective implementation of Visual Resources Conditions of Certification VIS-2, VIS-3, and VIS-5 would be sufficient to reduce the impact of the hybrid ACC or the dry cooling (ACC) option to a level that would not be significant. Therefore, the proposed project is equal to the PVID, dry cooling and hybrid cooling options.

The impact of water vapor plumes on aircraft using the nearby Blythe Airport is discussed separately in the Traffic/Transportation and Land Use Sections, along with the potential impact of the thermal plumes of the gas turbines on aircraft landing and departure from the airport.

The PVID irrigation return water supply option, or any other water supply substitution option, would not be expected to change the plume frequency and size characteristics of the proposed cooling tower. The dry cooling option would completely eliminate the cooling tower visible plumes and would not be expected to change the turbine/HRSG visible plumes. The hybrid cooling option would reduce the visible plume impacts from those of the proposed wet cooling tower that have been found to be less than significant. Therefore, related to visible plumes, all of the cooling options are similar in that none are expected to cause significant visible plumes to occur.

5.10 WASTE MANAGEMENT

Introduction

The purpose of this analysis is to evaluate whether the wastes generated through the use of degraded water and cooling options will be detrimental to the public and the environment.

PVID’s Irrigation Return Water Supply Option

The use of PVID’s irrigation return water for wet cooling should generate hazardous and nonhazardous waste streams similar to those expected through the use of the Colorado River groundwater. This is because all waste generating activities would basically remain the same in both instances.

Compliance with LORS proposed for the BEP II project involving the Colorado River groundwater should ensure that the generated wastes would be managed in an environmentally safe manner.

Dry Cooling

Waste streams that are typically associated with wet cooling activities will be eliminated as a result of using dry cooling. Overall, a smaller volume of wastes would therefore be generated during the project’s life cycle.

Hybrid Cooling

The hybrid option comprises 1/3 wet and 2/3 dry cooling. A reduced waste stream associated with wet cooling can therefore be expected through the use of hybrid cooling.

Conclusion

Both dry and hybrid cooling can be expected to generate a smaller quantity of wastes vis-a-vis wet cooling. Waste streams generated through the use of irrigation return water for wet cooling can be expected to be similar to those generated through the use of the Colorado River groundwater.

5.11 WORKER SAFETY

Introduction

The purpose of this analysis is to evaluate the use of degraded water, and the different cooling methods and technologies to determine if any additional impacts to worker safety or fire protection services may be expected.

PVID's Irrigation Return Water Supply Option

The use of irrigation return water from the PVID would require construction of a 1.5 mile water supply pipeline from PVID's Rannells Drain to BEP II. Conveyance of the irrigation return water would most likely require one pump station located at the new turnout from Rannells Drain.

Analysis of Construction and Operations Impacts

Excavation activities may encounter potentially contaminated soils and/or groundwater. Therefore, proper handling procedures may be necessary. A Phase I Environmental Site Assessment will be needed for any pumping station site and pipeline route prior to site preparation and a Phase II Environmental Site Assessment may also be needed. Once proper environmental site assessments have been conducted, the potential impacts to workers will be clearer. Standard worker safety regulations, including those for trenching, confined spaces, and exposure to hazardous wastes must be followed. Please also refer to the **Waste Management** and **Worker Safety/Fire Protection** sections of the PSA for discussions on contaminated soils and worker safety standards that specify appropriate mitigation measures and Conditions of Certification to ensure impacts on workers are less than significant.

Fire protection impacts are expected to be no different from those identified for the construction and operations of the proposed BEP II as described in the AFC and can be addressed by adherence to the LORS and proposed Conditions of Certification found in the Staff Assessment.

Dry Cooling

In a dry cooling system, fans blow air over a radiator system to remove heat from the system via convective heat transfer (instead of once-through cooling or evaporative heat transfer). The type of dry cooling analyzed in this document is direct dry cooling, also known as an air-cooled condenser (ACC). Because no cooling water is needed, there are several pieces of equipment that can be eliminated when using ACC. Cooling water supply piping, storage tanks, on-site chemical treatment equipment, and waste discharge piping are unnecessary with an air-cooled system.

Analysis of Construction and Operations Impacts

Worker Safety and Fire Protection impacts are expected to be no different from those identified for the construction and operations of the proposed BEP II as described in the AFC and can be addressed by adherence to the LORS and proposed Conditions of Certification found in the Staff Assessment.

Hybrid Cooling

Hybrid cooling systems combine wet and dry cooling technologies. This analysis considers a hybrid cooling system where 2/3 of the cooling requirements might be provided by ACC, and 1/3 by available non-potable water.

Analysis of Construction and Operations Impacts

Worker Safety and Fire Protection impacts are expected to be no different from those identified for the construction and operations of the proposed BEP II as described in the AFC and can be addressed by adherence to the LORS and proposed Conditions of Certification found in the Staff Assessment.

Conclusion

All of the cooling options described above would consist of some earthmoving and routine construction activities. Worker safety regulations, including those addressing trenching, confined spaces, and hazardous wastes must be followed. The risk to workers would not change significantly with any of the water supply or cooling options. This is mostly due to the generic nature of worker and fire protection required at a power plant licensed by the CEC.

Fire protection impacts are expected to be no different from those identified for the construction and operations of the proposed project as described in the AFC and can be mitigated by following all LORS and the proposed Conditions of Certification found in the PSA.

Staff therefore concludes that the impacts to workers and fire protection are similar with all water supply and cooling options.

5.12 SOCIOECONOMICS

Introduction

This section examines the potential impacts of alternative water supply and cooling options to community services and/or infrastructure and related community issues such as environmental justice.

PVID's Irrigation Return Water Supply Option

The PVID alternative will use 3,262 acre-feet per year, or the same amount of water as BEP II. Both options will take water away from agricultural use. Both options have the potential to cause direct and cumulative significant impacts to agricultural production and jobs.

Dry Cooling

No significant impact due to the small amount of water used for cooling.

Hybrid Cooling

No significant impact due to the small amount of water used for cooling.

Conclusion

The reduction in agricultural production will result in an insignificant change to Riverside County's annual crop revenues. However, looking at the change in water use on a local level shows that BEP I's water use of 3,262 acre-feet when combined with water usage proposed by BEP II will total 6,524 acre-feet per year from the local aquifer, or twice the amount of water used for agriculture in Mesa Verde. Taking 1,617 acres out of irrigated production to allow agricultural water to be used for BEP I and BEP II may directly and cumulatively impact agricultural production and the economy in the farm labor, farm services, and farm supply sectors in Mesa Verde. The applicant has not stated where fallowing will occur or which type of cropland will be fallowed.

BEP II is located about two miles from Mesa Verde/Nicholls Warm Springs, a small, unincorporated residential and largely Spanish-speaking community in the Palo Verde Mesa. The environmental justice demographic screening analysis shows the majority of the population in this area are low-income people of color, who depend largely on agriculture for jobs.

Fallowing of 1,617 acres will result in an insignificant change to Riverside County's annual crop revenues, as a whole. Fallowing of 1,617 acres in the Mesa Verde area to allow for water usage by BEP I and BEP II could result in a significant impact on the local economy and a disproportionate impact to an environmental justice community whose livelihood is largely dependent upon agriculture.

The use of either dry cooling or hybrid cooling would mitigate this impact to a less than significant level.

5.13 SOIL & WATER RESOURCES

Introduction

This discussion evaluates potential impacts resulting from using one of the various water supply options and cooling technologies. The Applicant has proposed using groundwater for cooling and process purposes at an average annual rate of 3,262 AFY and a maximum annual rate of 4,500 AFY with a wet cooling tower.

PVID's Irrigation Return Water Supply Option

Construction of the approximately 1.5-mile water supply pipeline from a new turnout on PVID's Rannells Drain could lead to erosion of soils. Soil types along the pipeline alignment tend to be a sandy loam, which characteristically are free-draining and have low erosion properties. Control of soil erosion would be further assured by preparing and implementing a Sediment and Erosion Control Plan (SECP). The SECP would specify Best Management Practices (BMP's) for conservation of topsoil, grading plans to restore existing contours for storm water drainage, temporary use of straw or mulch if needed, and restoration of vegetation. The pipeline would be installed along existing right-of-ways and adjacent to existing roads to the extent possible to minimize new disturbance to lands.

Irrigation return water from PVID's Rannells Drain and the associated irrigation return system is currently discharged into the Colorado River. The irrigation return water is not treated and has a relatively high concentration of Total Dissolved Solids (TDS) averaging about 1,630 mg/l, which contributes to increasing salinity concentrations in the Colorado River. The discharge negatively degrades Colorado River water quality for other uses, including other municipal drinking water supplies and maintaining aquatic habitat for sensitive species. The use of irrigation return water by the BEP II would result in a net improvement to Colorado River water quality by reducing the quantity of high TDS irrigation return water being discharged to the Colorado River. It would also reduce the amount of Colorado River water available to downstream users, which is considered a significant impact.

Dry Cooling

Dry Cooling would reduce the quantity of water required for BEP II process and cooling demands to about 40 AFY compared to the 3,262 fy average annual demand required for the wet cooling towers proposed by the Applicant. While water use is greatly conserved by using Dry Cooling, additional land would be disturbed. The disturbance of an additional 1 acre of land (an increase from 0.5 to 1.5 acres) is needed to implement Dry Cooling. This additional land disturbance could be mitigated to avoid soil erosion by implementation of the SECP.

Hybrid Cooling

This option would provide a Hybrid Cooling Tower designed for water conservation comprised of 1/3 wet and 2/3 dry cooling for the steam turbine. Water use for the Hybrid Cooling would use 1/3 of the water needed for the proposed Wet Cooling System. This would reduce water use from an average of 3,262 AFY to about 1,100 AFY. While the facilities for the Hybrid Cooling would have a slightly larger footprint, increasing from about 0.5 to 1.0 acre, the disturbance to soil could be mitigated by implementing an SECP. Although cooling tower blowdown would be reduced by about 2/3, water quality would not be affected due to the ability to recover a portion of the wastewater using the evaporator (brine concentrator) with the brine proposed to be distributed to two 8-acre evaporation ponds.

Conclusion

None of the alternative water supply and cooling options would result in a significant adverse impact with respect to soil erosion or degradation of water quality. However, all options other than dry cooling would result in significant impacts to downstream Colorado River water users. Dry cooling would conserve significant amounts of fresh water and minimize impacts associated with water use by BEP II.

5.14 GEOLOGY/PALEONTOLOGY

Introduction

This section evaluates the potential impacts of the degraded water source pipeline and the dry and hybrid cooling systems in the areas of geology and paleontology.

Detailed geological discussion and information about the project's alternative water supply linears was not included in the AFC (Caithness Blythe II, LLC, 2002) or in this document describing the alternative water supply and cooling options at the BEP II plant. However, given the geology and borings present at the BEP II plant site, potential for these hazards along the alternate linear facilities exists. In order to accurately assess the potential for liquefaction, dynamic compaction, hydrocompaction, subsidence, and expansive soils along the alternative water supply linears, subsurface exploration and associated laboratory testing and analyses should be performed during the design-level geotechnical investigation per **Conditions of Certification GEN-1**, **GEN-5**, and **CIVIL-1** in the **Facility Design** section.

PVID's Irrigation Return Water Supply Option

Use of PVID's irrigation return water would result in the construction of a new water supply linear from the Rannells Drain to the BEP II plant site. The two proposed water supply linear alternatives traverse Quaternary alluvium that consists of sands, gravels, silts, and clays (Stone, 1990).

Faulting and Seismicity

The proposed alternative water supply linears are located within Seismic Zone 3, as delineated on Figure 16-2 of the CBC (2000). No faults are mapped as crossing the proposed water linears. The closest known Holocene (active) faults are the Brawley Fault, Elmore Ranch Fault, and the San Andreas Fault (Southern and Coachella segments), located approximately 61 miles southwest of the alternative water supply linears. CEC staff has calculated an estimated deterministic peak horizontal ground acceleration for the Brawley Fault, Elmore Ranch Fault, and the Southern and Coachella segments of the San Andreas Fault as 0.05g, 0.05g, 0.08g, and 0.08g, respectively. These estimates are based on a moment magnitude 6.5, 6.6, 7.4, and 7.4 earthquake on the Brawley Fault, Elmore Ranch Fault, and the Southern and Coachella segments of the San Andreas Fault, respectively.

Liquefaction, Subsidence, and Expansive Soils

The potential for liquefaction along the alternative water supply linears is expected to be low given the depth to ground water in excess of 88 feet below the ground surface near the BEP II plant site; however, liquefaction potential may exist in close proximity to the Rannells Drain. A detailed geotechnical investigation and analysis of liquefaction potential, subsidence, and expansive soils should be included in the engineering geology/soils report required for final design.

Slope Failures

The potential for landslides along the alternative water supply linears is considered low, except at the edge of the mesa near the Rannells Drain where the potential is considered moderate due to high topographic relief. The proposed alternative linear alignments are generally located along existing roads.

Geologic, Mineralogic, and Paleontologic Resources

Staff has reviewed applicable publications regarding geologic and mineralogic resources. No known geologic or mineralogic resources are known to exist along the proposed alternative water supply linears.

The Quaternary alluvium traversed by the proposed alternative water supply linears is also present at the BEPI plant site where two vertebrate fossils were identified during construction of the plant. Based on this information and staff's review of available information (San Bernardino County Museum, 2002), the proposed alternative water supply linears have moderate potential to contain significant paleontological resources.

Dry Cooling

Implementation of dry cooling would require the construction of air-cooled condensers (ACC) immediately adjacent to the proposed plant. This site is geologically similar to the BEP II plant site and geologic hazards and geologic and paleontologic resources sections in the PSA would apply due to the close proximity to the BEP II plant site.

Hybrid Cooling

If the hybrid cooling option would utilize PVID's irrigation return water from the Rannells Drain, the geologic hazards and geologic and paleontologic resource discussion would apply from the PVID's Irrigation Return Water Supply Option section above. Otherwise, the geologic hazards and geologic and paleontologic resources sections in the PSA would apply since the hybrid cooling equipment is located within the footprint of the BEP II plant site.

Conclusion

Seismicity represents the main geologic hazard along the linear alignments with moderate potential for slope failures near the edge of the mesa and liquefaction near the Rannells Drain. In order to accurately assess the potential for liquefaction, dynamic compaction, hydrocompaction, subsidence, and expansive soils along the alternative water supply linears, subsurface exploration and associated laboratory testing and analyses should be performed during the design-level geotechnical investigation per **Conditions of Certification GEN-1**, **GEN-5**, and **CIVIL-1** in the **Facility Design** section. No geologic or mineralogic resources are known to exist adjacent to the proposed linear alignments. Since the proposed linear alignments will have significant excavation during construction and paleontologic resources were identified at the BEP I plant site during excavation activities, **Conditions of Certification PAL-1** through **PAL-7** from the BEP II PSA in the **Geology, Mineral Resources and Paleontology** section are designed to mitigate any paleontological resource impacts to a less than significant level.

5.15 POWER PLANT RELIABILITY AND EFFICIENCY

PVID's Irrigation Return Water Supply Option

Neither reliability nor efficiency of the power plant should be significantly affected by the use of reclaimed or degraded water (City of Blythe's treated wastewater or PVID's irrigation return flows).

Reliability Impacts of Dry Cooling

Dry cooling relies on the dry bulb temperature of the ambient air to provide the needed cooling effect. In hot climates at the BEP II site, extremely hot days may degrade cooling system performance, causing partial curtailment of power. The amount of reduced capacity of the steam turbine is a function of balancing the greater capital cost of the ACC in relation to the lost revenue of the lower peak power output on the few high ambient temperature days. Only the applicant can perform the economic optimization of the dry cooling system design in order to optimize the magnitude of impacts to plant reliability on the extremely hot days experienced at the BEP II site.

The dry cooling system design has been used in the power industry for several years now, and can be expected to exhibit typically high availability.

Efficiency Impacts of Dry Cooling

Dry cooling will typically provide less effective cooling, reducing the efficiency of the steam cycle portion of the power plant, and thus the overall fuel efficiency of the facility. The efficiency drop is due to a loss in LP turbine efficiency, as a result of operating the LP turbine at a higher back pressure. Since only about one-third of the power from a combined cycle power plant is produced by the steam cycle, this negative impact on fuel efficiency is diluted. An analysis of the Sutter Power Project (97-AFC-2) showed that annual average fuel efficiency would be reduced 1.5 percent compared to a wet cooling system. A similar reduction in efficiency could be expected for the Blythe II Energy Project.

Reliability Impacts of Hybrid Cooling

There are many variations of design of hybrid cooling that may perform the cooling function in this situation. The breakdown of wet to dry cooling options that are both incorporated into the hybrid design influence the reliability of the power plant. As the hybrid cooling design shifts from a majority wet cooling system to a majority dry cooling system, the hybrid cooling system becomes less reliable due to the increased possibility of power curtailment. A hybrid cooling system can be expected to yield reliability at least as great as a dry cooling system, and probably greater, due to the inherent redundancy of the combination of dry and wet systems. Significant adverse impacts on plant reliability from use of hybrid cooling are therefore unlikely.

Efficiency Impacts of Hybrid Cooling

A hybrid cooling system can be expected to provide cooling more effectively than a dry cooling system, especially on the very hot days when dry cooling system performance would show the most degradation. While less effective on an annual average basis than a wet cooling system, a hybrid system would reduce the loss of power plant fuel efficiency to less than the 1.5 percent reduction that might be expected with a dry cooling system. Incorporation of a hybrid cooling system would thus present less of an adverse impact on fuel consumption than dry cooling, but would still likely be less efficient than a wet cooling system.

Conclusion for Reliability

Wet cooling is the most reliable method for cooling the BEP II. Hybrid cooling may exhibit a slight adverse impact on plant reliability, but it is not expected that these impacts would be significant. For dry cooling, only the applicant can perform the economic optimization of the ACC design in order to optimize the magnitude of significant impacts to plant reliability on the extremely hot days experienced at the BEP II site. Use of reclaimed or degraded water from the City of Blythe's treated wastewater or PVID's irrigation return flows respectively, should have no significant impact on plant reliability.

Conclusion for Efficiency

Wet cooling would yield maximum fuel efficiency. Dry cooling would likely provide a reduction of fuel efficiency up to 1.5 percent; hybrid cooling would likewise reduce fuel efficiency, but to a lesser degree. Use of reclaimed or degraded water from the City of Blythe's treated wastewater or PVID's irrigation return flows respectively, should have no significant impact on fuel efficiency.

6. CONCLUSIONS

An Air Cooled Condenser and a Hybrid System consisting of 2/3 ACC and 1/3 Evaporative cooling were both considered and compared to the proposed evaporative cooling tower system and use of Colorado River groundwater supply. As part of the hybrid cooling system, an alternate water source using irrigation return water from PVID is considered. All three cooling design options are feasible at this location. Of the two alternative water supplies considered in detail, only irrigation return water from PVID is available in adequate quantities and is feasible for serving BEP II. The major consequences of each alternative are listed in Soil & Water Resources Appendix Table 8 below.

Based on the compilation of environmental and engineering measures presented in Soil and Water Resources Appendix Table 8, staff believes Alternative 4 – Dry Cooling is a preferable alternative to the proposed use of Colorado River groundwater and wet cooling (Proposed Project). Staff has identified potentially significant adverse impacts associated with the Proposed Project in the following three areas:

1. Land Use - Due to loss of production of local agricultural lands;
2. Socioeconomics – Due to fallowing 1,617 acres in the Mesa Verde area to allow for water usage by BEP I and BEP II, which could result in a significant impact on the local economy and a disproportionate impact to an environmental justice community whose livelihood is largely dependent upon agriculture.

3. Water Resources – Due to inconsistency with LORS and significant direct and significant cumulative impacts to other users of Colorado River water;

When accounting for financial elements and no lost power effects from hybrid or dry cooling, all alternatives are equivalent in cost to the proposed project. Even after accounting for lost power generation, the incremental effect on the cost of power production is only about .0006 to .0012 cents per KWH higher to implement dry cooling compared to the proposed project (using power values ranging from $30/MWH to $60/MWH). Neither of these increments of cost will significantly affect project economics or the owner's ability to market power. While Dry Cooling would require an additional capital investment of about $12 million over the capital cost of the proposed project which is attributable to the larger cooling tower, annual BEP II O&M costs are about $800,000 less for Dry Cooling compared to the proposed project as attributable to lower water pumping, treatment and purchase costs, which effectively makes the alternatives comparable in out-of-pocket cost over the life of the project.

From a water conservation standpoint and to achieve consistency with state regulations and policies including those of the CEC, dry cooling would accomplish the highest conservation of Colorado River water pumped as groundwater, reducing average annual water use from 3,262 AFY to about 40 AFY. No new water supply infrastructure (wells, pumps or off-site pipelines) would be needed, as the minimal 40 AFY needed to support dry cooling could be made available using the existing BEPI infrastructure. Staff believes conservation of water supplies throughout California, but particularly in the Colorado River basin, is imperative, considering that all of California's entitlements from the Colorado River are fully allocated, the need to preserve the highest quality water for the highest beneficial use consistent with state regulations and policies, and that California is mandated to reduce its historical use by over 1 million AFY. Dry cooling is an entirely feasible technology used in numerous power plants in California and elsewhere where there are either insufficient water supplies, or where the impacts would be adverse and significant to local or regional water supplies. Staff has concluded that this is the case with the proposed water supply for BEP II.

In considering the Proposed Project, staff believes that due to a lack of clarity for BEP II's proposed use in terms of entitlement, availability, USBR Accountability, and LORS/policy conformance issues, BEP II's consumptive use of Colorado River groundwater will cause significant direct and significant cumulative impacts to other users of this resource. The reasons are five-fold:

1. Applicant has linked its proposed use of Colorado River groundwater to the USBR-recognized PVID entitlement to Colorado River water through the WCOP. PVID believes that a water supply contract between the BEP II Applicant and itself would be a more straight-forward way of accounting for BEP II's water use. The WCOP has associated significant direct and potentially significant cumulative impacts (see Soil and Water Resources section).
2. PVID has not formally authorized BEP II use of groundwater, because it does not normally regulate groundwater use within its District.
3. USBR, USGS, CRB, PVID and staff believe Mesa groundwater is within the Colorado River accounting surface, yet USBR has no current generally applicable

methodology to account for groundwater use (see Soil and Water Resources section).

4. The groundwater-surface water hydrology within the PVID indicates that consumptive use of Colorado River groundwater by the project will be counted against PVID's allocation based on diversion less return (see Soil and Water Resources section).
5. There is uncertainty whether PVID can legally provide Colorado River water to the project with a water supply contract (see Soil and Water Resources section).

The compilation of environmental and engineering measures comparing the proposed project with alternatives for water supply and cooling is presented below in **Soil and Water Resources Appendix Table 8.** Measures with potential significant adverse impacts or inconsistency with LORS are shaded for ease of recognition.

Soils and Water Resources Appendix Table 8
Environmental & Economic Summary of Alternatives and the Proposed Project

Environmental & Economic Measure	Proposed Project	Alt. 1	Alt. 2	Alt. 3	Alt. 4
	Colorado River Groundwater & Wet Cooling	**Reclaimed Water from City of Blythe's WWTP & Wet Cooling**	**Irrigation Return Water from PVID & Wet Cooling**	**Irrigation Return Water from PVID & Hybrid Cooling**	**Dry Cooling**
Air Quality – PM10 Construction Emissions	Base Case No Sig. Impact	Not Evaluated in detail due to Water Supply not being available in sufficient quantity	Higher Emissions No Sig. Impact	Higher Emissions No Sig. Impact	Higher Emissions No Sig. Impact
Air Quality – PM10 Operation Emissions	Base Case No Sig. Impact		Same as Base Case No Sig. Impact	Lower Emissions No Sig. Impact	Lower Emissions No Sig. Impact
Biological – Cooling Tower Habitat Loss for Burrowing Owl & Desert Tortoise	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Biological – Water Pipeline Habitat Loss for Burrowing Owl & Desert Tortoise	No Significant Impact		Route B Preferred No Significant Impact	No Significant Impact	No Significant Impact
Cultural Resources – Effects to Historically Significant Resources	No Significant Impact		Can Mitigate PotentialSignificant Impact	No Significant Impact	No Significant Impact
Geology & Paleontology – Effects to Paleontologic Resources	Can Mitigate Potential Significant Impacts		Can Mitigate Potential Significant Impacts	Can Mitigate Potential Significant Impacts	Can Mitigate Potential Significant Impacts
Hazardous Materials	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Land Use – Power Plant Site Consistency with County LORS	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Land Use – Linear Facilities Consistency with County LORS	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Land Use – Effect on Agricultural Lands	Potential Significant Impact		Potential Significant Impact	Potential Significant Impact	No Significant Impact
Land Use Effects – Airport Plan Consistency	Potential Significant Impact		Potential Significant Impact	Potential Significant Impact	Potential Significant Impact
Noise	No Significant Impact		No Significant Impact	No Significant Impact	Can Mitigate Potential Significant Impacts
Power Plant Reliability & Efficiency	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Public Health	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Socioeconomics	Potential Significant Impact		Potential Significant Impact	Potential Significant Impact	No Significant Impact
Traffic/Transportation	Can Mitigate Potential Significant Impacts		Can Mitigate Potential Significant Impacts	Can Mitigate Potential Significant Impacts	Can Mitigate Potential Significant Impacts
Traffic/Transportation – Airport Safety	Potential Significant Impact		Potential Significant Impact	Potential Significant Impact	Potential Significant Impact
Visual - Effects from Cooling Structures	Can Mitigate Potential Significant Impact		Can Mitigate Potential Significant Impact	Can Mitigate Potential Significant Impact	Can Mitigate Potential Significant Impact
Visual - Water Pipelines	No Significant Impacts		No Significant Impacts	No Significant Impacts	No Significant Impacts
Waste Management	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Worker Safety	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Soil & Water Resources - Sediment & Erosion Control	No Significant Impact		No Significant Impact	No Significant Impact	No Significant Impact
Soil & Water Resources – Colorado River Water Quality	Slight Degradation No Significant Impact		Slight Improvement -No Significant Impact	Slight Improvement No Significant Impact	Slight Improvement No Significant Impact
Soil & Water Resources – Adequacy of Water Supplies to Meet BEP II Peak Demands	Adequate in 2006	Recycled Supply Not Adequate	Adequate in 2006	Adequate in 2006	Adequate in 2006
Soil & Water Resources – Compliance with Water LORS	No		Yes	Yes	Yes
Soil & Water Resources – Total Water Supply & Cooling Costs w & w/o Lost Power Revenues (2003$, 7%, 30 Years)	**$47,680,577**	**$51,470,804**	**$51,788,560**	**$51,448,577 - $67,381,786**	**$48,778,620 - $73,209,540**
Soil & Water Resources – Incremental Power Production Cost ($/KWH)	**$0.00117/KWH**	**$0.00126/KWH**	**$0.00127/KWH**	**$0.00126- $0.00166/KWH**	**$0.00120 - $0.00180/KWH**

Note: The Incremental Power Production Cost for Alternatives 3 and 4 when accounting for the lost power revenues (due to a reduction of generating capacity associated with hybrid and dry cooling) increases from $0.00166 to $0.00205 per KWH for Alternative 3 and from $0.00180 to $0.00240 per KWH for Alternative 4 when assuming a value of power production foregone ranging from $30/MWH to $60/MWH.

Staff also concludes that Alternative 1 – Reclaimed Water from City of Blythe's WWTP with Wet Cooling is not presently a viable alternative due to the following:

1) The potential supply of reclaimed water is not sufficient to meet BEP II demands over the life of the project, while other sources of lesser quality water already exist (See Soil & Water Resources Appendix Tables 1 and 2).
2) City of Blythe does not have any existing or foreseeable plans to implement Title 22 tertiary wastewater treatment or a reclaimed water program.
3) The use of reclaimed water would essentially be use of Colorado River water.

CONSISTENCY OF ALTERNATIVES WITH THE CALIFORNIA CONSTITUTION, WATER CODE AND STATE WATER POLICY

Staff has determined implementation of the Proposed Project– Use of Colorado River Groundwater would be considered a waste or unreasonable use or unreasonable method of use (see Soil and Water Resources Technical section) of water as defined in the State Constitution, Water Code and other relevant LORS and policies including those of the CEC. State policy promotes the highest and best use of fresh inland water, as well as, conservation of fresh water supplies when possible. A significant number of state statutes set forth policy statements and findings promoting these essential concepts in relation to water quality and resources. These numerous statutes consistently promote efficient use and conservation of California's valuable water resources.

Results of the overall analysis comparing the characteristics of various water supply and cooling alternatives for consistency with State policy for fresh water conservation as related to LORS is as follows:

1. <u>Ultimate Dependency on Fresh Water</u> – This is a measure of the extent of fresh water conservation that is achievable. Alternative 4 – Dry Cooling and Alternative 3 – Hybrid Cooling would diminish fresh water needs for process and cooling to an average of 40 AFY and 1,100 AFY respectively. . Alternative 2 – PVID's Irrigation Return Water would use an average of 3,262 AFY of the most degraded water available. Reclaimed water from City of Blythe's WWTP – Alternative 1 is neither available, nor is it projected to be sufficient to supply BEP II demands within the initial 30 years of the BEP II project. The Proposed Project using groundwater from on-site wells, would use an average of 3,262 AFY of the highest quality of water available, other than Colorado River surface water, but has associated unmitigated significant direct and significant cumulative impacts.

2. <u>Adequacy of Water Quality Before Treatment</u> – All sources of water supply are adequate for use in power plant cooling at BEP II except for City of Blythe's wastewater which would need to be treated to a disinfected tertiary level. City of Blythe has no current plans to upgrade its wastewater treatment from advanced secondary treatment to teritiary. Staff has considered the water treatment

requirements using a range of water quality from best case using groundwater with a TDS of 1,010 mg/l to worst case using irrigation return water from PVID with TDS averaging about 1,630 mg/l. The distinctions in treatment requirements for each alternative are reflected in the economic analysis.

3. Effect of Recycled or Degraded Water Use on Public Health – Neither Colorado River groundwater nor PVID's irrigation return water would have any adverse impacts on public health. In order to use recycled water from City of Blythe's WWTP, it would first need to be treated to Title 22 tertiary standards in order to avoid potential effects to public health.

4. Adverse Effects to Downstream Water Rights – Dry cooling – Alternative 4 would most clearly avoid adverse impacts to other existing and senior users who have entitlement to Colorado River water. The next best case would be Hybrid Cooling – Alternative 3, which requires only an average of 1,100 AFY water supply. Staff believes that due to a lack of clarity for BEP II's proposed use of groundwater in terms of entitlement, availability, USBR Accountability, and unmitigated significant impacts, that the Proposed Project could potentially impact other users who have senior entitlements to Colorado River water.

5. Degradation to Water Quality – None of the alternatives would result in a degradation to water quality compared to existing conditions. Alternative 2 – PVID's Irrigation Return Water has the greatest potential to contribute to improving water quality of the Colorado River. Alternative 2 would utilize up to 6.2 cfs and an average annual quantity of 3,262 AFY of the most degraded water readily available to BEP II. Alternative 2 would avoid discharge of the irrigation return water, which averages a TDS of 1,630 mg/l into the Colorado River, which averages a TDS of about 640 mg/l.

6. Injury to Plantlife, Fish & Wildlife – With respect to water use, none of the alternatives would cause a significant adverse impact to plantlife, fish and wildlife. For Alternative 2 – Irrigation Return Water from PVID with Wet Cooling and Alternative 3 – Hybrid Cooling, the preferred water supply pipeline route is Alternative B because it reduces potential impacts to the riparian vegetation in the Rannells Drain. Please see the discussion of Biological Resources in Section 5.2 of this Appendix A as well as the Biological Resources Technical section of the Staff Assessment for further discussion of impacts.

7. Reasonable Cost of Water Supply – Based on the preliminary cost comparison as shown in **Soil & Water Resources Appendix Table 7**, and before accounting for lost power generation due to reduced capacity with hybrid or dry cooling, all alternatives are comparable in cost. Even after accounting for lost power generation, the incremental effect on the cost of power production is only about .0006 cents per KWH comparing dry cooling to the proposed project, which in staff's view is neither an insignificant effect on project economics nor on the owner's ability to market power.

These measures are consistent with the criteria set forth under California Water Code Section 13500 et seq. State water policy requires that an examination of alternatives to fresh water for cooling purposes be conducted. In conducting this examination staff has considered the factors set forth under California Water Code Section 13500 et, seq. Staff has concluded that two feasible alternative cooling methods – Dry and Hybrid Cooling and one feasible alternate water supply associated with wet cooling –Irrigation Return Water from PVID, is available.

Staff also believes that based on its cost analysis, its conclusions are consistent with a new policy being considered by the Energy Commission. In the Draft 2003 Integrated Energy Policy Report, the Committee is recommending that the Energy Commission adopt a policy that would only approve the use of fresh water for power plant cooling purposes by power plants when alternative water supply sources and cooling technologies are shown to be “environmentally undesirable” or “economically unsound” (CEC 2003a, Page 36).

Staff also finds that its recommendation for conservation of water supply through use of Dry Cooling at BEP II – Alternative 4 is further supported by the recent release of the Draft CA Water Plan Update 2003. On October 6, 2003, CA Department of Water Resources (DWR) posted a draft of the CA Water Plan Update 2003 (Bulletin 160) to begin receiving comments from stakeholders. Bulletin 160 is updated every five years, and for 2003, the process has included input from a broadly diverse Advisory Committee consisting of 65 members representing all primary interest groups. The draft report includes projections of the state’s population growth, which is expected to increase by an average 600,000 people per year, realizing a 50 percent increase by 2030. The report also identifies the need to provide 3 to 5 million AFY of water for the increasing population and correcting groundwater overdraft, and an additional un-quantified amount for unmet environmental purposes. The recommended measures for providing this additional water supply to California do not rely on any significant new surface storage projects, but instead rely on capturing a variety of conservation and reclamation projects. The recommended measures with the highest level of confidence for implementation include urban and agricultural water use efficiency improvements, recycling municipal wastewater, conjunctive management, water transfers and desalinization of brackish water. (DWR 2003) With this vision for California’s water future, it is imperative that water be conserved whenever reasonable, feasible, and environmentally sound consistent with state policies and guidance.

APPENDIX A.1 - BACKGROUND ON WATER SUPPLY AND COOLING OPTIONS

A.1.1 BEP II PROPOSED POWER PLANT OPERATION AND COOLING

The project as proposed would consume approximately 3262 AFY or approximately 2,220 gallons per minute (gpm) annual average of Colorado River ground water pumped from a well located on the project site. Additional emergency back-up water source from the Blythe Energy Project (BEP) would be used if required due to problems with the on-site well.
The proposed project will use the water for three purposes:

- process makeup at a rate of approximately 108 AFY

- evaporative cooling in a conventional cooling tower at a rate of approximately 3019 AFY
- and for gas turbine inlet cooling at an extremely variable rate which will average approximately 135 AFY over the year.

The proposed cooling towers are not plume-abated; visible plume would be expected infrequently at this location due to the low moisture content of the ambient air under most conditions. The drift from the towers is proposed at 0.0006% of circulating water flow. The cooling towers and supporting water treatment systems are designed for seven cycles of concentration.

Blowdown from the cooling tower is treated by a brine concentrator in order to separate the blowdown into two streams; one of high purity/low dissolved solids and the other of high dissolved solids concentration. The brine concentrator design is based on a mechanical vapor compression process. The brine concentrator recovers approximately 95.5 % of the blowdown from the cooling tower. This recovered water is recycled to the plant as feed to the cooling tower and as feed to the demineralizer, which supplies the plant process water – distilled high purity water. The approximately 4.5% of water that is not returned to the cooling tower or plant process, is discharged to the evaporation pond.

The plant includes a single 8-acre Evaporation Pond. However, the AFC proposes a connection to the existing BEP evaporation ponds in order to provide flexibility by mutual management of all three ponds. The evaporation ponds provide a holding for the high solids waste water from the brine concentrator. In addition, any of the ponds may be taken out of service and the remaining water allowed to evaporate over a period of years. When this is accomplished, the remaining solids in the pond(s) will be removed for disposal at a solids disposal site.

In the AFC and supplements, the applicant proposes using Colorado River ground water as feed source for a conventional evaporative cooling tower for steam turbine exhaust cooling. After several design variations, the applicant now intends to accomplish GTIC (gas turbine inlet cooling) using a mechanical refrigeration cooling system. The mechanical cooling system will use an evaporative cooling tower for its ultimate heat sink, located on top of the cooling system structure at the gas turbine inlet. Both cooling towers are designed without plume-abatement.

Cooling in both evaporative coolers – main cooling towers and inlet air cooling towers – is accomplished by the evaporation of water. Evaporation takes advantage of the "fugacity" or heat of evaporation that occurs in changing the state of water from liquid to vapor. This heat content is very large on a per-pound basis compared to the change per pound of water during non-evaporative heating and cooling. However, because evaporation adds moisture to the air that is swept into the cooling towers, and discharged vertically, there is a possibility of creating vapor plumes from the towers. The Blythe airport is very near the project site, so the consequences of a plume are investigated in other parts of this Staff Analysis. Experience from the first Blythe project should be informative.

Thermal power plants convert fuels (such as natural gas) to electrical power and waste heat. In combustion turbines, or Brayton cycles, almost all the waste heat is rejected in the exhaust gases. In steam turbines, or Rankine cycles, waste heat is rejected in the flue gases and in the condenser/cooling system. BEP II is a combined cycle facility that incorporates both combustion turbines and steam turbines. The combustion turbines will require water for inlet cooling and the hot exhaust gases will be used to generate steam to drive the steam turbines. The steam turbines require cooling for efficient power generation. Operation of a cooling system for steam turbines serves three purposes:

(1) condensing steam into water to allow pumping of a liquid instead of compressing a gas to raise the feedback to the boiler to high pressures;

(2) recycling of the water back to the boiler to optimize water use; and

(3) minimizing the steam turbine exhaust pressure to maximize the output of the steam turbine. The temperature of the heat sink and the heat transfer efficiency of the cooling system affect the overall plant performance. In the case of the BEP II, the proposed cooling medium (or heat sink) is obtained by evaporation of Colorado River ground water.

This section describes three general cooling technologies: dry cooling, hybrid cooling, and wet cooling systems. General background information, conceptual design information, and possible environmental effects are presented for each cooling technology. In addition, this section describes using alternative sources of water of lesser quality instead of fresh ground water for cooling. **Soils and Water Resources Appendix Table A.1.1** presents a summary of the most recently operational and approved combined cycle power plants, and indicates the type of cooling water used, the cooling system, and whether ZLD was implemented.

Soil and Water Resources Appendix Table A.1.1
Recent Operational and Approved Combined Cycle Power Plants

	Project Name	MW	County	Cooling Method	Water Source	Zero Liquid Discharge
Operational	Delta Energy Center	880	Contra Costa	Wet Cooling	Reclaimed water	No
	GWF Hanford Peaker	96	Kings	Wet Cooling	Fresh water	No
	Los Medanos	559	Contra Costa	Wet Cooling	Reclaimed water	No
	Moss Landing Expansion	1060	Monterey	Once-through cooling	Ocean water	No
	La Paloma	1048	Kern	Wet Cooling	Fresh water	No
	Sunrise Combined Cycle	320	Kern	Wet Cooling	Fresh water	No
	Sutter Power **	540	Sutter	Dry Cooling	None	Yes
Approved/Under Construction	Blythe Energy	520	Riverside	Wet Cooling	Fresh water	No
	Contra Costa Repower	530	Contra Costa	Wet Cooling	Recycled water	No
	Cosumnes	500	Sacramento	Wet Cooling	Fresh Water	Yes
	Elk Hills	500	Kern	Wet Cooling	Fresh water	No
	High Desert	720	San Bernardino	Wet Cooling	Fresh water	Yes
	Huntington Beach Repower	450	Orange	Once-through cooling	Ocean water	No
	Russell City	600	Alameda	Wet Cooling	Reclaimed water	No
	Palomar	546	San Diego	Wet Cooling	Reclaimed water	No
	Metcalf	600	Santa Clara	Wet Cooling	Reclaimed water	No
	East Altamont	1100	Alameda	Wet Cooling	Blended reclaimed water	Yes
	Mountainview	1056	San Bernardino	Wet Cooling	Blended reclaimed water	No
	Otay Mesa	510	San Diego	Dry Cooling	None	No
	Three Mountain Power	500	Shasta	Wet/dry Cooling	Fresh and reclaimed water	Yes
	Western Midway Sunset	500	Kern	Wet Cooling	Fresh water	Yes
Source: California Energy Commission, September 2003						

** For comparison purposes, Sutter Energy Center is in an area where 1% highest temperature is 101 ºF, compared to Blythe at 112 ºF. Sutter uses a 30 cell ACC, and is reported to have increased plant cost by $10 million. Staff anticipates BEP II would use a 45 cell ACC costing $18 million. (Source Fahey). See below.

A.1.2 DRY COOLING SYSTEMS

Description of the Process and Equipment Required

There are two types of dry cooling systems: direct dry cooling and the lesser used indirect dry cooling. In both systems, fans blow air over a radiator system to remove heat from the system via convective heat transfer (instead of using water for cooling or evaporative heat transfer). In the direct dry cooling system, also known as an air-cooled condenser (ACC), steam from the steam turbine exhausts directly to a manifold radiator system that rejects heat to the atmosphere, condensing the steam inside the radiator.

This process is illustrated in **Soil & Water Resources Appendix Figure 3** (See Part 3 of this report). Direct dry cooling at BEP II is analyzed in this report.

Indirect dry cooling uses a secondary working fluid (in a closed cycle with no fluid loss) to help remove the heat from the steam. The secondary working fluid extracts heat from the surface condenser and is transported to a radiator system that is dry cooled (fans blow air through the radiator to remove heat from the working fluid). Because indirect dry cooling is not very common and does not appear to have any particular advantages at the BEP II, it was not analyzed in this report.

Historic, Current, and Proposed Use of Dry Cooling

Dry cooling was first used in 1938 for a vacuum steam turbine installed in a power plant in Germany (Guyer, 1991). By 1971, 14 power plants worldwide had been equipped with condensers for direct dry cooling. The largest installation at that time was a roof-mounted unit for a 160 MW power plant in Utrillas, Spain. By 1991, dry cooling was being used at approximately 40 power plants worldwide with generating capacities greater than 100 MW. Since that time, the use of dry cooling has increased significantly around the world and in the United States (Guyer, 1991; EPA, 2001; Maulbetsch, 2001).

The largest dry-cooled system in the world today is the Matimba plant in South Africa, which began operating in 1991. It represented a major scale-up of dry-cooled technology, using direct dry cooling for six, 660 MW units, totaling 3,960 MW.

The Sutter Power Plant, one of the newest power plants in California (on-line in 2001) was constructed as a dry-cooled facility. This plant was constructed by Calpine Corporation and is a 540 MW, natural gas-fired, combined cycle facility. The combined cycle design consists of two CTGs, two HRSGs with duct burners, and a STG. The Sutter Power Plant uses a 100 percent dry cooling design that reduces groundwater use by over 95 percent from the original proposal of 3,000 gallons per minute (gpm) to a revised annual average of less than 140 gpm. The remaining five percent represents the makeup for the steam cycle, and other non-cooling plant processes. To treat the plant wastewater stream, Sutter uses a zero liquid discharge system that eliminates any discharge of any process waste fluids to land or water.

The Energy Commission also permitted the Crockett Co-Generation Plant, a 240 MW co-generation facility with dry cooling in Crockett, which went on-line in 1995. The Crockett Co-Generation Plant uses 12 fans to cool the steam output from the 80 MW steam turbine. Energy Commission staff visited the facility in June 2000 and found the dry cooling to be operating as expected, with no major problems. The Energy Commission also permitted in 2001 the Otay Mesa facility, a 510 MW combined-cycle facility in San Diego County. Reliant Energy has also proposed a new dry-cooled facility, the 500 MW Colusa Power Project that proposes using 40 fans. This project was undergoing environmental review by the Energy Commission when its application for certification was withdrawn.

Dry cooling is also becoming a common technology for power plants in Nevada. Currently, the El Dorado Energy Project is the only operational air-cooled power plant facility in the State of Nevada. This 480 MW combined cycle facility is located in Boulder City. Two other combined cycle air-cooled power plants are currently under construction in Nevada: the Duke Energy 1,200 MW Moapa Energy Facility (approximately 20 miles northeast of Las Vegas in Apex Industrial Park) and the 575 MW Big Horn Power Plant (in Primm, approximately 55 miles southwest of Las Vegas). In addition, there are four combined cycle air-cooled power plants proposed for construction in Nevada. These facilities include: Apex Generating Station (1,100 MW), Arrow Canyon (575 MW), and Silver Hawk (570 MW) facilities at the Apex Industrial Park, and the Copper Mountain Power Facility (600 MW) in Boulder City.

Dry cooling represents 69 percent of the total proposed power plant capacity in Massachusetts. Of this capacity, 525 MW are approved, 750 MW are on-line and 2,905 MW are under construction (Dougherty, 2002).

Dry cooling is also considered to be a feasible technology by the New York Department of Environmental Conservation, which has recently required dry cooling to replace once-through cooling in certain applications. New York has one 1,080 MW dry cooling plant under construction and eight others with a combined total generation of 5,328 MW that are at various stages of the approval process (Radle, 2002).

Energy Commission staff research indicates that the use of dry cooling technology is expanding rapidly, and the size of the plants using dry cooling is also increasing. It is estimated that there are over 2,500 MW of U.S. power generated using dry cooling, and approximately 15 to 20 GW worldwide. Roughly 15 percent of the projects under construction and in development (approximately 40,000 MW) are projected to be either 100 percent dry cooled or wet/dry hybrid cooled (Ortega, 2002).

Advantages and Disadvantages of Dry Cooling

Dry cooling is the best choice of cooling technologies for a steam power plant with regard to water conservation since it conserves about 95 percent of the water otherwise demanded by wet cooled systems and minimizes the volume of wastewater. However, this technology can raise environmental and economic issues, depending on the location and specific situation (these are reviewed for the BEP II site specifically in Section 5 of this report). The following is a general list of the advantages and disadvantages of dry cooling.

Advantages of Dry Cooling Systems

- Dry cooling saves valuable fresh water for other beneficial uses.
- Dry cooling is not water dependent so plant location is not tied to a water source. It has essentially no water intake or water discharge requirements.
- Dry cooling minimizes the use of water treatment chemicals.
- Dry cooling minimizes the generation of liquid and solid wastes.
- Dry cooling does not generate visible plumes that are commonly associated with wet cooling towers.
- Dry cooling eliminates impacts to aquatic biological resources.
- Dry cooling eliminates the need for disturbance of wetland/aquatic substrate habitat.

Disadvantages of Dry Cooling Systems

- Dry cooling requires air-cooled condensers that can have negative visual effects.
- Dry cooling requires the disturbance of a larger surface area for the air-cooled condensers than is required for wet cooling towers.
- Dry cooling can have noise impacts that are greater than wet cooling systems because of the number of fans and the considerably greater total airflow rate. New quieter fans and other mitigation measures are available to reduce these impacts.
- Using dry cooling, the power plant steam cycle efficiency and output can be slightly reduced, depending on site conditions and seasonal variations in ambient conditions. Also, extra power is needed to operate the cooling fans.
- Capital costs for building air-cooled condensers are generally higher than capital costs for wet cooling or once-through cooling.

Dry cooling can also be used for gas turbine inlet air-cooling (GTIC). Mechanical refrigeration cooling design, similar to a typical room air conditioner but very much larger, is proposed by the Applicant. As in a room air conditioner, it is possible to use direct air-cooling for the heat sink rather than evaporative cooling. This option is included in the dry cooling study of applicant's AFC Appendix 6.0. For this study, the small amount of water for GTIC, 0 to 230 AFY approximately, was not separately considered, but is included as part of the overall BEP II requirements amounting to an annual average of 3300 AFY.

A.1.3 WET EVAPORATIVE COOLING

Description of the Process and Equipment Required

Wet evaporative cooling systems typically use about 5 percent to 15 percent of the water used by once-through wet cooling systems (historically used for cooling power plants located on the coast or on large water bodies). In wet evaporative cooling, water is used to remove waste heat from the system through cooling towers, and is then recirculated. In evaporative cooling systems, process heat is removed by evaporation each time the water is cycled through the system. **Soil & Water Resources Appendix Figure 2** shows how a typical evaporative cooling system operates (see Part 3 of this report).

The cooling system must be replenished with "makeup water" to replace water "lost" (or consumed by) to evaporation, blowdown1, and drift. Evaporation removes heat, but also consumes cooling system water, and increases the concentration of impurities. Blowdown volumes are dependent on the quality of the makeup water, and the system specifications regarding the impurities that are in the makeup water.

1 Blowdown is the bleeding off of a small percentage of the total flow, so that the new, more pure makeup water balances impurities. In this way, the water in the system stays within operational specifications as well as meeting any quality requirements for discharge.

Current Uses of Wet Cooling

Evaporative cooling is one of the most common technologies in the world for the removal of waste heat, including many applications at power plants. Evaporative cooling towers used by U.S. industries remove heat using approximately 500 billion gallons of water per day (Burger, 1994).

Advantages and Disadvantages of Wet Cooling

The following is a general list of the advantages and disadvantages of evaporative wet cooling.

Advantages of Wet Cooling Systems

Wet cooling removes heat by the evaporation of a fraction of the recirculating water. Once a wet cooling system is filled, the only water withdrawn from the environment is makeup water to replace water lost to evaporation, blowdown, and drift.
Capital costs for a wet cooling system are less than those of dry cooling. Wet cooling can reach "wet bulb2" temperatures, which are generally lower than "dry bulb3" temperatures, thus improving cooling efficiency in comparison to dry cooling systems.
Wet cooling can use lesser quality or degraded water such as recycled water from wastewater treatment plants, thereby avoiding the use of fresh water.

Disadvantages of Wet Cooling Systems

Wet cooling requires a dependable source of water, and on a total plant basis, requires a volumetric factor on the order of 100's more water than dry cooling systems.
Wet cooling requires water treatment and monitoring to control concentrations of impurities.

Wet cooling can produce water vapor plumes that have negative aesthetic effects.

A.1.4 HYBRID (WET/DRY) COOLING

Description of the Process and Equipment Required

Hybrid cooling systems combine wet and dry cooling technologies. There is a wide range of system designs possible, covering the entire spectrum of wet versus dry depending on plant needs.

At one end of the spectrum is the "plume abatement cooling tower" design. In this case, an otherwise conventional evaporative cooling tower is designed with a small dry section. The name "plume abatement" comes from a primary purpose of this dry section: to eliminate the visible plume by cooling the circulating water/heating the air-water discharge from the cooling tower so that the discharge does not fall below the dew point and cause a visible plume. Plume abatement wet cooling typically has the ability to achieve 3 percent "dry" cooling and 97 percent "evaporative wet" cooling.

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2 Wet bulb temperature accounts for the relative humidity in the air (the largest differences between wet and dry bulb temperatures would occur in very dry conditions).
3 Dry bulb temperature is the temperature indicated by an ordinary thermometer that does not account for moisture in the air.

At the other end of the spectrum is “spray enhanced air dry cooling.” In this design, an air-cooled condenser is “enhanced” by spraying cooling water directly into the steam before it enters the air-cooled condenser. While a range of designs is possible, a typical design would use 75 percent “dry” and 25 percent “wet” cooling (Maulbetsch, 2001).

Despite the ends of the spectrum described above, a more typical hybrid cooling system would utilize both an air cooled condenser and an evaporative cooling tower within the same cooling system, and would achieve a ratio of wet to dry cooling that would be on the order of 50 percent. This is sometimes called a “water conservation design”, and may also be called “parallel condensing cooling system”.

The most common of the wet/dry systems is the plume abatement cooling tower. However, its usage is primarily to minimize visible plume, rather than to reduce water consumption for evaporation through full-time use of the dry section. The steam turbine exhaust is condensed simultaneously in both a surface condenser, which in turn is cooled by an evaporative cooling tower, and an air-cooled condenser. During operation, the condensing pressures in both the surface condenser and the air-cooled condenser constantly equilibrate due to the self-adjustment of steam flows entering each device. As ambient conditions, load conditions, and head rejection capability of each device vary over time, the steam flow to each will automatically adjust without active components being required on the steam side (Duke, 2001a).

Current Use of Hybrid Cooling

Plume abatement wet/dry towers have been used since the 1970s with proven reliability. The parallel condensing cooling systems (with both a wet tower and a dry cooling tower) have been used since at least since the late 1980s. GEA Power Cooling Systems, Inc. (GEA) is one vendor that provides a parallel condensing system called the PAC Parallel Condensing System. This system combines reliable wet cooling and dry cooling tower technologies.

Advantages and Disadvantages of Hybrid Cooling

The following is a general list of the advantages and disadvantages of parallel condensing hybrid cooling.

Advantages of Parallel Condensing Hybrid Cooling Systems

- Water conservation hybrid systems may be designed to use anywhere from 20 percent to 80 percent of the water used in evaporative cooling tower systems. Evaporative systems require 5 percent to 15 percent of the flow required for once-through cooling systems.

- Once a parallel condensing hybrid cooling system is filled, the only water withdrawn from the environment is makeup water to replace water lost to evaporation, blowdown, and drift. Water consumption is reduced by the amount of dry cooling.

- Parallel condensing hybrid cooling can reach “wet bulb” temperatures in the wet portion of the system. These wet bulb temperatures are generally lower than “dry bulb” temperatures, thus improving cooling efficiency in comparison to an all-dry cooling systems.

- Because of the lowered water requirements, parallel condensing hybrid cooling systems can match project cooling water demands with limited quantities of fresh or recycled water that may be available.

Disadvantages of Parallel Condensing Hybrid Cooling Systems

- Parallel condensing hybrid cooling requires a dependable source of water.
- Although more efficient than dry cooling, the parallel condensing hybrid cooling system is less efficient than once-through or wet cooling.
- Parallel condensing hybrid cooling systems require water treatment and monitoring to control concentrations of impurities.
- The wet cooling side of the hybrid system can produce water vapor plumes that may have negative aesthetic effects.
- Capital and maintenance costs for hybrid systems are generally higher than once-through or wet systems since two systems are needed.
- Hybrid cooling systems can have noise impacts that are greater than wet cooling systems because of the increased number of fans and greater total airflow associated with the air cooled condensers. New quieter fans and other mitigation measures are available to reduce these impacts.

A.1.5 USE OF RECLAIMED OR DEGRADED WATER FOR POWER PLANT COOLING

Description of Water Treatment Processes

In many parts of California, treated wastewater is made available to industrial and agricultural customers for cooling or irrigation uses. Reclaimed or degraded water is generally priced at 50 to 90 percent of the cost of potable water. The use of reclaimed or degraded water at a power plant would not generally require additional equipment at the power plant itself, other than possibly increasing the capacity of water treatment systems for treating higher levels of total dissolved solids. As is typical with all power plants requiring a source of water, pipelines from a source of reclaimed or degraded water would need to be constructed and connected to power plant water intake systems.

There are two processes for treating reclaimed sewage water to an acceptable level for use in a generating facility: secondary wastewater treatment and tertiary wastewater treatment. The process for secondary wastewater treatment removes biodegradable organics and suspended solids, using chemical and/or biological processes. Tertiary treated wastewater is treated to nearly drinking water standards, requiring disinfection to kill any microorganisms that might cause disease. This can be done with chemical [e.g., chlorine] and/or physical [e.g., microfilter] processes.

The degree and type of treatment processes are determined by the proposed end use of the reclaimed or degraded water. Many large water treatment plants have a multi-user distribution system to enable unrestricted use by any customer; these wastewater treatment plants usually provide tertiary treatment followed by disinfection, because this meets the needs of California Wastewater Reclamation Criteria (Title 22). Title 22 identifies four different effluent quality levels, each matched to a set of probable uses.

Title 22 requires that any cooling system creating a mist such as those used at a power plant must use disinfected tertiary-treated reclaimed water. The requirement to use tertiary treated wastewater is due to the potential exposure to human contact from cooling tower mist or drift. Tertiary treated water is also required for unrestricted use where there is a high risk of public contact, such as landscape or food crop irrigation, and groundwater injection.

Current Uses of Reclaimed Water

The use of reclaimed water for non-potable processes and cooling tower makeup has been practiced for over half a century and is well established in California and is an integral part of most long-range water plans. SWRCB Policy 75-58 prioritizes the use of lower-grade water, such as reclaimed water over fresh inland water for power plant cooling. In addition, the California Water Code considers the use of potable-grade fresh water for non-potable uses, such as cooling tower makeup, an unreasonable use when reclaimed water is available. While irrigation is the primary use of reclaimed water in California, its seasonal nature requires seasonal storage or another method of effluent discharge during the non-irrigation season. Cooling tower makeup is the next greatest use of California reclaimed water and its year round demand enables higher utilization of installed facilities.

The Sacramento Regional Wastewater Treatment Plant currently provides secondary effluent to SMUD for its Carson-Ice Generating facility cooling and the City of Lodi's treatment plant provides secondary effluent to two power generating facilities.

Since 1999, the Energy Commission has approved a number of combined cycled power plants utilizing tertiary treated reclaimed water for wet cooling and in some cases for process (steam) supply and landscape irrigation. Those already operational include the 555 MW Los Medanos Power Plant and the 880 MW Delta Energy Center. Power plants approved and pending construction include the 328 MW Magnolia Project, 600 MW Russell City Energy Center, 546 MW Palomar Energy Project, and 1,100 MW East Altamont Energy Center. The Energy Commission is currently reviewing several more plants that propose to use reclaimed water including the Inland Empire Energy Center and San Joaquin Valley Energy Center, and is very closely scrutinizing projects that have not fully considered use of reclaimed or degraded water where available.

Advantages and Disadvantages of Use of Reclaimed Water for Power Plant Cooling

The following is a general list of the advantages and disadvantages of cooling using reclaimed water.

Advantages of Cooling Using Reclaimed Water

- Reclaimed water, which may otherwise be directly discharged to surface waters or the ocean, has a beneficial use prior to discharge.
- The discharge volume of effluent pollutants is reduced.

- The water source is dependable even if a drought occurs.
- The purchase of reclaimed water stimulates local economic development.
- High-quality freshwater resources are preserved for drinking water supply, which maintains public health.
- There are no documented public health problems and the use of reclaimed water gains strong public acceptance.

Disadvantages of Cooling Using Reclaimed Water

- Reclaimed water may not always be readily available in the large quantities required.
- As is typical with all power plants requiring a source of water, pipelines from a source of reclaimed or degraded water would need to be constructed and connected to power plant water intake systems.
- Additional water reclamation treatment may be necessary for unrestricted use.

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GLOSSARY

A glossary of terms used in this Appendix A.

Gpm: Gallons per minute, a flow rate for water.
Acre foot: The volume of water stored in an acre of surface area and one foot in depth equivalent to 325,851 gallons.

AFY: Acre-Feet per year. A volume of water supplied or consumed over the course of one year;.

Mgd: Million Gallons per Day.

CFS: commonly called "second feet", is actually cubic feet per second. This is another common measure of flow rate of water. One cfs is 448 gpm.

GTIC: Gas Turbine Inlet Cooling. Gas Turbines ingest large amounts of air to use both as working fluid and for combustion. Gas Turbines are very sensitive to the temperature of the incoming air; lower air temperature increases the capacity of a turbine as well as the efficiency to a great extent. In order to improve both capacity and efficiency, inlet air may be cooled, either by mechanical chiller or by evaporative means such as spraying a fine mist of water directly into the air entering a turbine.

Heat of Fugacity: The additional heat required to boil water after it reaches boiling temperature.

Drift: the extremely small amount of water that leaves an evaporative cooling tower in droplets suspended in the air steam leaving the tower.

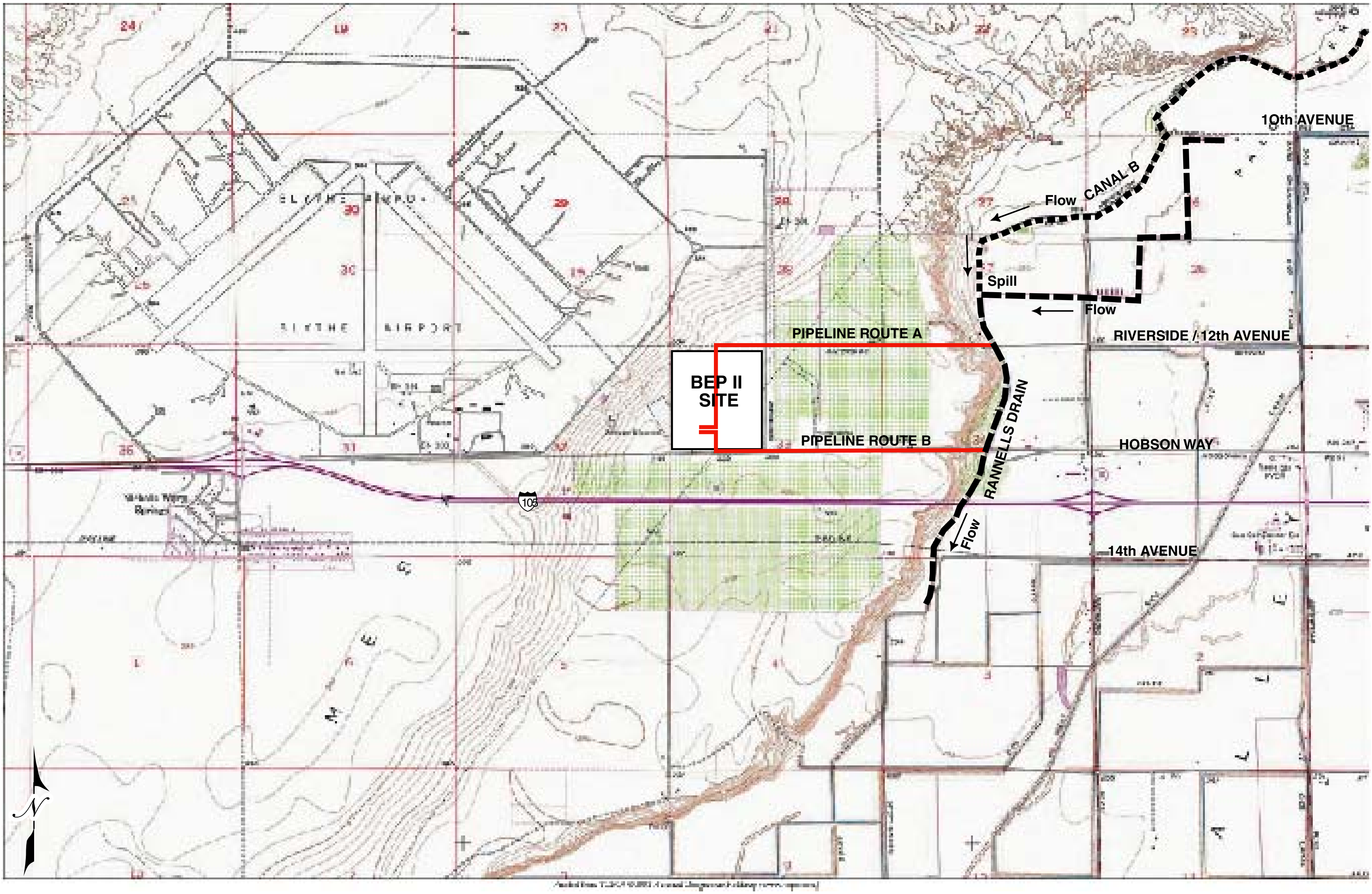
Blowdown: the water that is drained/discharged continuously from the cooling tower basin and sent to waste – the evaporation pond in the proposed project. Blowdown is necessary because the evaporation of water increases the concentration of chemicals in the basin. Total water consumption in a cooling tower is evaporation plus blowdown plus drift.

Wet bulb temperature: The temperature recorded by a thermometer in air but cooled by a packing of wet gauze on the bulb – thus the wet bulb. The thermometer without the wet gauze is said to record dry bulb temperature. Traditionally matching thermometers were built, one with a wet bulb the other dry, and the difference used as an expression of the amount of water present in the air – humidity. When the humidity in the air is enough that both bulbs read the same, it is said that dewpoint is reached; This is indicative that there is so much moisture in the air that none can be evaporated from the wet gauze and cool the wet bulb of the set, resulting in wet and dry bulbs reading the same. This condition is also 100% humidity.

WWTP: Wastewater Treatment Plant. Where effluent from public sewer system is treated prior to discharge or further use. POTW for publicly owned treatment works used interchangeably.

PVID: Palo Verde Irrigation District.

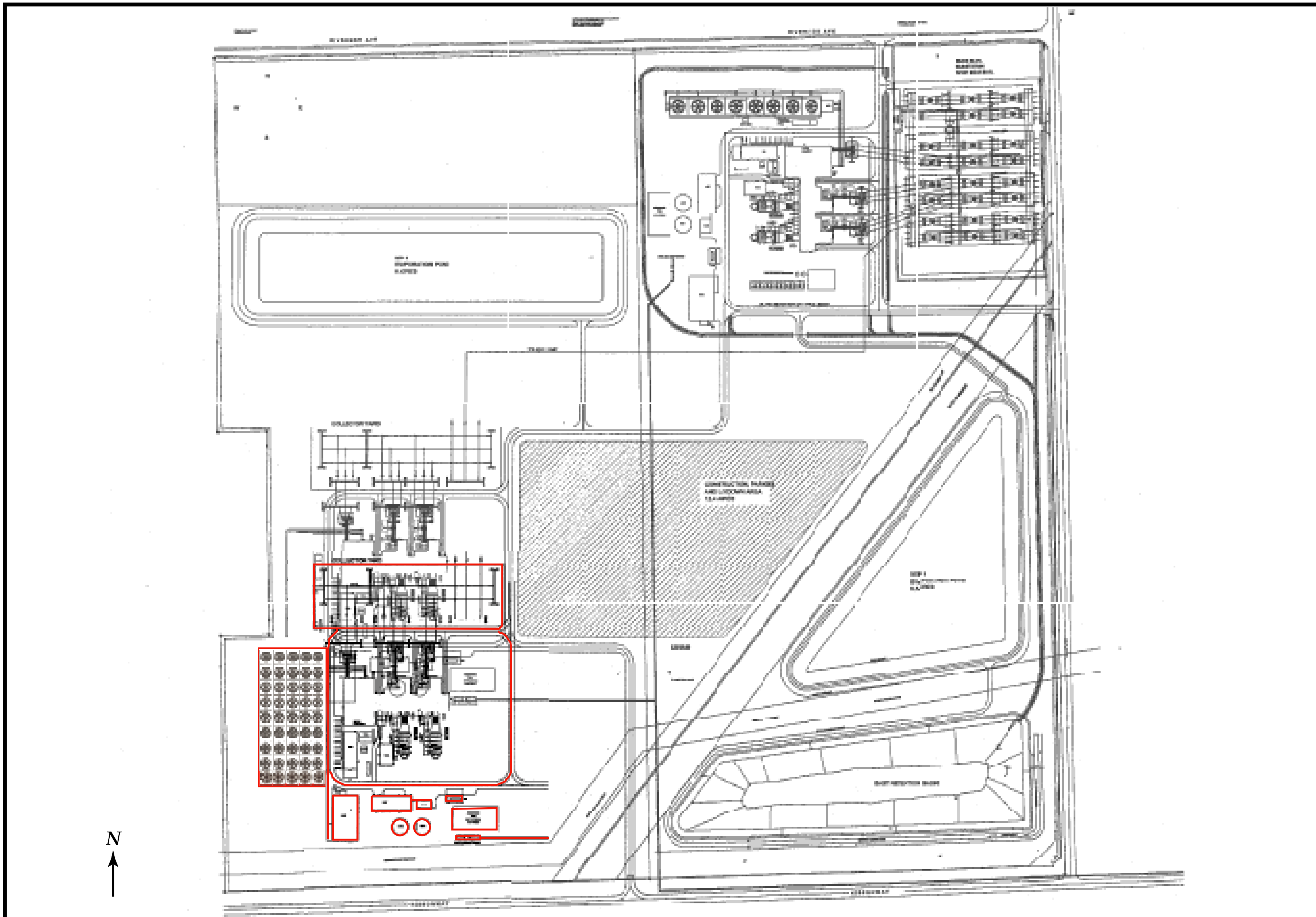
SOIL & WATER RESOURCES APPENDIX FIGURE 1
Alternative Water Pipeline Routes from PVID's Rannells Drain to Blythe Energy Project II



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: PVID

SOIL AND WATER RESOURCES APPENDIX FIGURE 4

BEP II Dry Cooling Arrangement



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: BEP II AFC Figure 2.0-24

TRAFFIC AND TRANSPORTATION

Ken Peterson

INTRODUCTION

The Traffic and Transportation section of the Preliminary Staff Assessment (PSA) addresses the extent to which the Blythe Energy Project Phase II (BEP II) may impact the transportation system in the local area. This analysis includes the identification of: the roads and routings which are proposed to be used for construction and operation; potential traffic-related problems associated with the use of those routes; the anticipated encroachment upon public rights-of-way during the construction of the proposed project and associated facilities; the frequency of trips and probable routes associated with the delivery of hazardous materials; and the possible effect of project operations on local airport flight traffic.

The influx of large numbers of construction workers can, over the course of the construction phase, increase roadway congestion and also affect traffic flow. In addition, the transportation of large pieces of equipment can impact roadway congestion and safety. Potential impacts related to traffic operations and safety hazards resulting from the construction and operation of the project are discussed below.

Refer to the **PROJECT DESCRIPTION** section of this PSA for a more detailed discussion of the project.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

Federal, state, and local LORS that are applicable to the proposed project are listed below

FEDERAL

The federal government addresses transportation of goods and materials in Title 49, Code of Federal Regulations:

- Title 49, Code of Federal Regulations, Sections 171-177, governs the transportation of hazardous materials, the type of materials defined as hazardous, and the marking of the transportation vehicles.
- Title 49, Code of Federal Regulations, Sections 350-399, and Appendices A-G, Federal Motor Carrier Regulations, addresses safety considerations for the transport of goods, materials, and substances over public highways.
- Title 49, Code of Federal Regulations, Section 44718 and Title 14, Code of Federal Regulations, part 77, addresses hazards to air navigation.
- Title 14, Code of Federal Regulations, Section 77.13(2)(I), requires an Applicant to notify the FAA of construction of structures with a height greater than 200 feet from grade or greater than an imaginary surface extending outward and upward at a slope of 10 to 1 from the nearest point of the nearest runway of an airport with at

least one runway more than 3,200 feet long. Staff is not aware of any FAA regulations addressing visible or thermal plumes.

STATE

The California Vehicle Code and the Streets and Highways Code contain requirements applicable to the licensing of drivers and vehicles, the transportation of hazardous materials, and rights-of-way. The California Health and Safety Code addresses the transportation of hazardous materials. Specific provisions include:

- California Vehicle Code, section 353 defines hazardous materials. California Vehicle Code, sections 31303-31309, regulate the highway transportation of hazardous materials, the routes used, and restrictions thereon;
- California Vehicle Code, sections 31600-31620, regulate the transportation of explosive materials;
- California Vehicle Code, sections 32000-32053, regulate the licensing of carriers of hazardous materials and includes noticing requirements;
- California Vehicle Code, sections 32100-32109, establish special requirements for the transportation of inhalation hazards and poisonous gases;
- California Vehicle Code, sections 34000-34121, establish special requirements for the transportation of flammable and combustible liquids over public roads and highways;
- California Vehicle Code, sections 34500, 34501, 34501.2, 34501.3, 34501.4, 34501.10, 34505.5-.7, 34506, 34507.5, 34510, and 34511, regulate the safe operation of vehicles, including those which are used for the transportation of hazardous materials;
- California Health and Safety Code, section 25160 et seq., address the safe transport of hazardous materials;
- California Vehicle Code, sections 2500 to 2505, authorize the issuance of licenses by the Commissioner of the California Highway Patrol for the transportation of hazardous materials including explosives;
- California Vehicle Code, sections 13369, 15275, and 15278, address the licensing of drivers and the classifications of licenses required for the operation of particular types of vehicles. In addition, it requires the possession of certificates permitting the operation of vehicles transporting hazardous materials;
- California Streets and Highways Code, sections 117 and 660 to 672, and California Vehicle Code sections 35780 et seq., require permits for the transportation of oversized loads on county roads; and
- California Street and Highways Code, sections 660, 670, 1450, 1460 et seq., 1470, and 1480, regulate right-of-way encroachment and the granting of permits for encroachments on state and county roads.

The California Public Utilities Code (PUC) contains sections that relate to power plant operations safety concerns:

- PUC section 21659 requires that the Caltrans Division of Aeronautics issue a construction permit for any structure that will penetrate a given airport's Federal Aviation Regulation Part 77 "imaginary surface".
- PUC sections 21402 and 21403c pertain to the issue of ground-based development or activity interfering with the right of flight.

LOCAL

Riverside County

General Plan Circulation Element

Although the BEP II project facilities would be located entirely within the City of Blythe, possible construction traffic routes include roads in the unincorporated area of Riverside County. Therefore, Riverside County LORS related to traffic and transportation are included. The Circulation Element of the Riverside County General Plan establishes LOS C as a Countywide target on all County-maintained roads and conventional State Highways, except that LOS D could be allowed in urban areas only at intersections of any combination of Major Streets, Arterials, Expressways, or conventional State Highways within one mile of a freeway interchange and at freeway ramp intersections in instances where LOS C is deemed to be impractical (Riverside County, p. 216).

Congestion Management Plan

State-mandated Congestion Management Plans (CMPs) were established in 1990, with the Riverside County Transportation Commission designated to implement the CMP for the region, including the Blythe area. The CMP directs local agencies (e.g. Riverside County and the City of Blythe) to maintain minimum level of service (LOS) thresholds.

Blythe Airport Comprehensive Land Use Plan

The Blythe Airport Comprehensive Land Use Plan (CLUP) and the Riverside County Airport Land Use Commission (ALUC) determination of inconsistency with the CLUP are discussed in the **LAND USE** section of this PSA.

CITY OF BLYTHE GENERAL PLAN CIRCULATION ELEMENT

The September, 1989 City General Plan contains a Circulation Element required by State law. The following Circulation Element goals, objectives, and policies are pertinent to the proposed power plant:

Transportation Demand Management Goal: To promote the use of non-single occupant modes of transportation, and to shift trips out of current peak periods. (City of Blythe 1989, p. III-38)

Objective 3.0 The City shall encourage employers to provide alternative work weeks and flextime sufficient to reduce peak period trips by 10%. (City of Blythe 1989, p. III-39) The following policy is in support of Objective 3.0:

Policy 3.1:	The City shall encourage employers to provide 4 day-40 hour and 9 day-80 hour work weeks, and/or provide start/end times outside of the 6-8 a.m. and 4-6 p.m. peak periods of traffic.
Policy 11	Provide and maintain roadway intersection operations at Level of Service (LOS) D or better at peak traffic volumes for all segments of the City's circulation system.

SETTING

REGIONAL DESCRIPTION

FREEWAYS AND LOCAL ROADWAYS

The project site is located in the City of Blythe approximately five miles west of the downtown area, 0.25 mi. north of Interstate 10 (I-10) within Riverside County in southeastern California. The site is 152 acres in size and is approximately one mile east of the Blythe Airport. **TRAFFIC and TRANSPORTATION Figure 1** shows the area of the project site. The project site is located in the Palo Verde Valley area of the County, in which agricultural resources are the most important economically. BEP II would be built on the 76-acre expansion portion of the Blythe Energy Project Phase I (BEP I) site, on the west side of the site.

The entire BEP I/BEP II 152-acre site is to the north of and adjacent to a City and County road called Hobsonway, and to the west and adjacent to Buck Boulevard. Construction of BEP has recently been completed, and the expansion site is unimproved. Hobsonway serves as the I-10 frontage road in the area and as the business loop for the City of Blythe (BEP II 2002a, p. 7.4-2).

Three highways, Interstate 10 (I-10), State Route (SR) 78 (Neighbours Boulevard) and United States Highway 95 (U.S. 95, Intake Boulevard) provide regional access to the plant site. I-10 is a major four-lane divided, east-west freeway that links the Greater Los Angeles Metropolitan Region eastward through Phoenix and Tucson, Arizona to New Mexico and points east. I-10 is located approximately 0.25 mile south of the BEP II site. U.S. 95 is a two-lane, north-south highway that provides north access to the City of Blythe via the cities of Vidal and Needles. US-95 is located approximately 6.5 miles east of the BEP II site, and continues north through California into Nevada and on to Las Vegas. SR 78 is a two-lane, north-south highway that provides south access to the Palo Verde Valley via the City of Brawley. SR-78 has its western terminus in San Diego County at Interstate 8, and is located approximately 1.5 miles east of the site.

From the west, the site is reached from the I-10/Mesa Drive interchange located near the airport and Hobsonway, which is in the County unincorporated area until reaching the City border at the western edge of the project site. From the east the site is reached via I-10 at interchanges located at SR-78, Lovekin Boulevard, or US-95, and then on Hobsonway to the site.

Neighbours Boulevard is a two-lane collector road to the south of I-10, and is considered a local road to the north of I-10 (Petritz 2003b). Lovekin Boulevard has four lanes north and south of Hobsonway; and then soon becomes a two-lane road in both directions. Intake Boulevard has two lanes. Lovekin and Intake Boulevards are arterial roads (City of Blythe p. III-35). **TRAFFIC and TRANSPORTATION Figure 2** (BEP II 2002a Figure 7.4-2) shows the project site vicinity.

Airport

The Blythe Airport is located approximately one mile west of the proposed BEP II site off of Hobsonway. The airport is outside the current boundary of the City of Blythe and is located in unincorporated Riverside County. The airport property includes the planned Blythe Airport Industrial Park area. Blythe Airport is owned by Riverside County, which contracts with the City of Blythe for operations.

Regional access to the airport is from I-10 at the Mesa Drive interchange. The airport is operated as a municipal general aviation facility and provides regional air services (BEP II 2002a, p. 7.4-7). There are two operating runways at Blythe Airport. Runway 8-26 (oriented east-west) is the primary runway and is 6,562 feet long, 150 feet wide. Runway 17-35 (oriented north-south) is 5,820 feet long, 100 feet wide. The airport can accommodate business jets and transport type aircraft (Coffman 1992, p. 2-1). Flight training companies make high use of this airport. Activity at the airport consists of an average of 67 aircraft operations per day (Air Nav). Aircraft using Runway 8-26, approaching from or departing to the east, fly over the BEP II site (Downs). The majority of the take-off and landings use Runway 8-26 (Coffman 2000, p. B-5).

Railroads

The Blythe area is served by the Arizona & California (A&C) Railroad which travels through part of the Palo Verde Valley. The railroad line accesses the valley from the northwest and then runs south through the City of Blythe. The A&C line terminates at Ripley, approximately seven miles southwest of the City of Blythe, and operates two days per week. This railroad line is used for transport of rail freight into and out of the Palo Verde Valley. Passenger service is not provided (Scott).

Public Transportation

Local bus service in the greater Blythe area is provided by the Palo Verde Valley Transit Agency. There is a bus stop at I-10 and Mesa Drive about 1.3 mile from the project site (Palo Verde Valley Transit Agency). This agency also operates dial-a-ride service for unincorporated areas and in the City of Blythe for seniors and the disabled (Palo Verde Valley Transit Agency) . The Greyhound company provides bus service to major California cities outside of the Blythe region (Greyhound Call Center).

Bike Lanes

The City of Blythe encourages the use of walking and bicycling as alternative modes of transportation and when appropriate incorporates bicycle and pedestrian facilities into the roadway design process. The City has adopted a non-motorized transportation plan that includes a Class II or III bike lane along Hobsonway in the vicinity of Blythe II. Hobsonway currently has no bicycle lanes in the vicinity of the site and none are planned. However, the City's Plan Review Committee has stipulated a requirement that BEP II accommodate the future installation of a Class II bike lane by including in the site plan sufficient width of pavement on the north side of Hobsonway (Petritz 2003a).

PLANNED ROADWAY AND TRANSIT IMPROVEMENTS

BEP II construction would require further street improvements. These improvements would include the above-mentioned Hobsonway street widening for a future bike lane, and if a portion of Riverside Drive is used for construction or emergency access, that portion would have to be paved (Petritz 2003a). If Hobsonway is used for transport of oversize and overweight loads, temporary structural support would be installed at the Hobsonway canal crossings due to canal crossing weight restrictions. The city has one major planned road improvement project, for Hobsonway, that coincides with project construction, existing traffic conditions **Table I** (BEP II, 2002a, Table 7.4-1, p. 7.4-4) identifies the existing annual average daily traffic (AADT), hourly highway design capacity, annual average peak-hour traffic, and peak hour level of service (LOS) for highways in the vicinity of the project. The traffic estimates are presented for various road segments between mileposts or junctions on each highway. Daily and peak hour traffic volumes are illustrated. All street segments shown have a peak hour of LOS A.

Table 1
Present Conditions of Affected Roadways

Street Segment	Classification	No. of Lanes	Average Daily Volume[1]	Hourly LOS D Thresh-hold[2]	Hourly Design Capacity[3]	P.M. Peak Hour Volume[4]	Peak Hour LOS
SR-78 S of Interstate10	Arterial	2	2,800	970	1,200	220	A
US-95 N of Interstate10	Arterial	2	5,100	970	1,200	410	A
Interstate10:	Freeway	4					
E of Mesa Dr.			17,100	7,130	8,800	1,650	A
W of Mesa Dr.			16,300	7,130	8,800	1,550	A
E of SR-78			17,100	7,130	8,800	1,650	A
W of SR-78			18,200	7,130	8,800	1,750	A
E of US 95			19,200	7,130	8,800	1,850	A
W of US 95			21,500	7,130	8,800	1,400	A

1—Estimated number of vehicles per day, based on 2000 Caltrans traffic counts.
2—Maximum number of vehicles per hour in one direction of LOS D.
3—Maximum number of vehicles per hour in one direction 4 Peak hour number of vehicles per hour, based on 1998 Caltrans traffic counts.

LOS levels refer to the average vehicle capacity and the flow of traffic. LOS A denotes free flow of traffic while LOS E and F means that there is a congested flow. The LOS criteria take into account numerous variables such as annual average daily traffic (AADT), lane capacity, grade, environment, and other relevant information. The State-mandated CMP authority in the area of the project site is Riverside County in unincorporated areas and the City within its boundaries. The County CMP's goal is LOS D when practical, and LOS E threshold represents the maximum vehicles per day that a highway or roadway can serve and still meet the minimum acceptable standard on the County roadway system (BEP II 2002a, p. 7.4-9). The City has adopted the County of Riverside CMP requirements. The City's General Plan vehicle capacity goal is also LOS D (City of Blythe, p. III-39). These adopted CMP goals are still valid, although the CMP has not been implemented in and around the City due to the low traffic volumes in these areas (BEP II 2002a, p. 7.4-9).

According to the AFC, "Traffic counts for local roadways are limited or nonexistent as neither the County of Riverside nor the City of Blythe measure traffic flows on roads near the site due to the rural nature and low traffic volume in the area." (BEP II 2002a p. 7.4-4). However, a traffic study prepared for the City of Blythe, the Palo Verde Valley Transportation Master Plan (Parsons Brinkerhoff), shows the following LOS values for local street locations important to project construction worker and truck traffic:

Table 2
Year 2000 Traffic Conditions

MID-BLOCK COUNT LOCATION	2000 LOS
Hobsonway west of Neighbours	A
Hobsonway east of Defrain	A
Hobson way between Lovekin and Broadway	A
Hobsonway between 7th St. and Intake	A
Intake between Hobsonway and I-10	A
Intake at I-10	A
Intake between I-10 and 14th Ave.	A
Lovekin between Hobsonway and I-10	A
Lovekin at I-10	A
Mesa between Hobsonway and I-10	A
Mesa at I-10	A
Neighbours at I-10	A

Source: Parsons Brinkerhoff p. 3-2

Table 3
Existing Intersection Conditions
PM Peak Hour – Unsignalized Intersections

INTERSECTION	1/28/00 LOS	1/29/00 LOS	5/26/00 LOS
Hobsonway/Intake	A	A	A
I-10 WB ramps/Intake	A	A	A
I-10 EB Ramps/Intake	B	B	B

Source: Parsons Brinkerhoff p. 3-4

Table 4
Existing Intersection Conditions
PM Peak Hour – Signalized Intersections*

INTERSECTION	1/28/00 LOS	1/29/00 LOS	5/26/00 LOS
Hobsonway/Lovekin	A	A	A
Hobsonway/7th	A	A	A

Source: Parsons Brinkerhoff p. 3-4
*Signalized intersections are analyzed using Intersection Capacity Utilization (ICU) methodology.

As shown in **Table 1**, all highways in the area currently operate at LOS A. Tables 2 – 4 demonstrate that representative local streets and intersections important to project construction are at LOS A except for one intersection at LOS B.

The AFC provides accident data from the Highway Patrol (Blythe Station) for I-10, SR-78, US-95 and unincorporated roadways in the vicinity of the project site for a period between 1997 and September 1999 (BEP II 2002a, p. 7.4-6). The data shows that accident rates range from 0.40 to 0.70 accidents per million vehicle miles (MVM) traveled. The 1997 Accident Data on State Highways (BEP II 2002a p. 7.4-6) indicates an average statewide accident rate of 2.4 MVM for roadway types corresponding to I-10 and 1.27 MVM for State Routes corresponding to US-95 and SR 78. The accident rates for the highways near the study area are well below statewide accident averages.

Airport

The Blythe Airport Master Plan has recently been updated by the City of Blythe, Riverside County and the Federal Aviation Administration (FAA). The primary objective of the Master Plan is to develop and maintain a long-term development program for the airport. The Master Plan update considers extending Runway 8-26 to 7,000 feet in order to accommodate larger aircraft (Coffman 2000 Table 3C, p. 3-7). The City of Blythe has indicated that any Master Plan proposals for the future extension of airport Runway 8-26 will be to the west only (Hull). This would extend the runway away from the project and from the populated downtown area.

ANALYSIS AND IMPACTS

According to Appendix G of the California Environmental Quality Act (CEQA) Guidelines, a project may have a significant effect on traffic and transportation if the project will:

- cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in a substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersections);
- exceed, either individually or cumulatively, a level of service standard established by the county congestion management agency for designated roads or highways;
- result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks;

- substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment);
- result in inadequate emergency access;
- result in inadequate parking capacity; or
- conflict with adopted policies, plans, or programs supporting alternative transportation (e.g., bus turnouts, bicycle racks).

PROJECT SPECIFIC EFFECTS

Facility Construction

The AFC provides an analysis of year 2005 traffic conditions plus project construction traffic trips (BEP II 2002a, Table 7.4-6, p. 7.4-5). An analysis of the peak hour forecast plus peak hour employee trips indicates that freeway segments in the area would continue to operate at LOS A. The AFC does not provide an analysis of the impact of project construction traffic on local roads. However, because the Palo Verde Valley Transportation Master Plan shows all local streets and intersections important to the project at LOS A for the near term (i.e., during the next 3-5 years), except for one intersection at LOS B (see Tables 2-4 above), it is staff's assessment that project construction traffic would not cause LOS values for local streets and intersections to fall below the minimum City and County standards. City staff concurs that project construction would not cause significant impact to local streets (Wellman 2003d).

Plant Site Workforce and Level of Service

Construction of the generating plant facility would occur over an estimated 18 to 20-month period and would require a peak (three month) construction workforce of 365 workers, assuming a single shift and a 40-hour, five to six day work week. (BEP II 2002a, pp. 7.4-9 and 10). Construction workers commuting from the greater Blythe area would travel west on Hobsonway or travel west on I-10 to the I-10/SR 78 interchange and then on Hobsonway to the site; those workers who live west of the site would travel east on I-10 to the Mesa Drive interchange and then on Hobsonway to the site. Workers from both directions would enter the site from Buck Boulevard. Workforce vehicle trips were calculated based on this data.

The applicant assumes an average automobile occupancy (AAO) of 1.1 persons per vehicle to represent a worst-case construction worker commute scenario (BEP II 2002a, pp. 7.4-11). Using the AAO rate of 1.1 results in approximately 660 daily trips to and from the site with a maximum of 330 vehicle trips during the p.m. peak hour. A worst-case scenario which assumes that all workers would drive individually to the project site would result in 770 daily vehicle trips to and from the site and a maximum of 365 trips from the site during the p.m. peak hour (BEP II 2002a, pp. 7.4-11). This is one possible scenario; however there are alternatives to single occupant vehicle trips such as a higher level of ride sharing that would lower project impact.

Construction activity would generally begin before 7:00 a.m. and end by 4:00 p.m., unless flexible work schedules are implemented (BEP II 2002a, p. 7.4-15). During the hot summer months the work schedule may be adjusted to evening or early morning hours in order to avoid the high temperatures (BEP II 2002a, p. 7.4-15).

Using the traffic pattern assumptions described above, **Table 5** (BEP II 2002a, Table 7.4-6, p. 7.4-15) shows that when the existing low traffic volume is combined with construction-related vehicle traffic, highways would continue to operate at LOS A.

Table 5
Estimated 2005 Daily and Peak Hour Construction Traffic Volumes And LOS Worst-Case Conditions

Street Segment	No. of Lanes	Daily Volume			P.M. Peak Hour Volume and LOS		
		Background Traffic	Proposed		Background Traffic	Proposed	
			Project Traffic	Cumulative Traffic		Project Traffic	Cumulative Traffic/LOS
South on SR-78 at the Interstate 10 Interchange	2	3,400	50	3,450	265	40	305 A
North on US-95 at the Interstate 10 Interchange	2	6,800	20	6,820	520	10	530 A
East on Interstate 10 at the Mesa Drive Interchange	4	23,080	690	23,770	2,145	325	2,470 A
West on Interstate 10 at the Mesa Drive Interchange	4	22,000	20	22,020	2,050	5	2,055 A
East on Interstate 10 at the SR-78 Interchange	4	25,440	640	26,080	2,180	285	2,465 A
West on Interstate 10 at the SR-78 Interchange	4	23,950	690	24,640	2,275	0	2,275 A

Parking and Laydown areas

Parking for construction worker vehicles and the laydown area for construction supplies and equipment would be provided on the power plant site (BEP II 2002a, Figure 2.0-24).

Truck Traffic

Construction of the generating plant would require the use and installation of heavy equipment and associated systems and structures. Heavy equipment would be used throughout the construction period, including trenching and earthmoving equipment, forklifts, cranes, cement mixers and drilling equipment. Project construction would add 25 trucks, or 50 trips, per day during the peak construction truck traffic month. An estimated 4,165 truck deliveries would be made to the plant site over the course of the 18-month construction period, for an average of 11 deliveries per business working day (BEP II 2002a, p. 7.4-11).

Project construction trucks would follow the same routes as those used for the original BEP (BEP II 2002a, p. 7.4-12). Access to the project site would be on I-10, SR-78 (Neighbors Boulevard), or US-95 (Intake Boulevard) to Hobsonway and then to Buck Boulevard which is adjacent to the site (BEP II 2002a, 7.4-10). Project traffic may also access the site directly from Hobsonway (BEP II 2002b, p. Traffic & Transportation 5). I-10 project truck traffic would access Hobsonway at Mesa Drive coming east and Lovekin Boulevard coming west. I-10, US-95, and Hobsonway presently incur a high level of truck traffic, whereas truck traffic on SR-78 is low. Most project construction truck traffic would use I-10 and US-95 (BEP II 2002b, p. Traffic & Transportation 5). I-

10 truck traffic averages about 5,900 trucks per day, or about 39% of total traffic on I-10 (BEP II 2002a, p. 7.4-10). Construction truck traffic from BEP II would not significantly alter the LOS values for I-10, SR-78, and US-95 (See Table 5).

The AFC states that since BEP I/BEP II construction would overlap, BEP II would require fewer truck deliveries (BEP II 2002a, p. 7.4-18). City staff has recently expressed a concern that, because BEP I construction has been completed, now there would be no BEP I/BEP II construction overlap, and so the AFC understates truck traffic (Wellman 2003a). However, in reviewing truck traffic on a monthly basis (see BEP II 2002a, Table 7.4-9, p. 7.4-20) staff has concluded that overall highway impact of increased project construction traffic is not significant with the adoption of the recommended conditions.

Construction Phase Transport of Hazardous Materials and Waste

Deliveries would also include small quantities of hazardous materials to be used during project construction. The applicant has stated that the deliveries of hazardous materials to and from the site would be conducted in accordance with California Vehicle Code Section 31300 et seq. (BEP II 2002a, pp. 7.4-15, 19). The applicant expects less than two hazardous materials trips per day during the construction period (BEP II 2002a, p. 7.4-12).

The AFC does not select a specific truck route for supplying and removing hazardous materials. However, it does note: "Pursuant to Section 31303 of the California Vehicle Code, the transportation of hazardous materials will be on state or interstate highways that offer the shortest overall transit time possible. The CHP has identified I-10, US-95, and SR-78 as roadways to be used in the transportation of designated hazardous materials." (BEP II 2002a, p. 7.4-15).

Construction Traffic Impact on School Bus Safety

The Palo Verde Unified School District bus route follows the routes that the project work force and construction trucks would take. However, school bus stops are at locations where there is sufficient room for buses to pull off the road, so there would be insignificant added risk to school bus occupants from project construction truck traffic (Hernandez). School locations are not on the project construction truck routes or the routes that the majority of the work force would follow.

Oversize and Overweight Loads

Transportation of equipment that would exceed the load size and limits of certain roadways would require special permits from the California Department of Transportation (Caltrans). California Streets and Highways Code, Sections 117 and 660-72, and California Vehicle Code 35780 et seq., require permits for the transportation of oversized loads on State and county roads. By law, Energy Commission certification takes the place of all necessary State, local and regional permits. However, staff typically requires applicants to get permits from Caltrans for oversized loads, encroachment and activities within road right-of-ways. Staff has proposed condition **TRANS-2** to ensure compliance with County and Caltrans vehicle size and weight requirements. The applicant has submitted a traffic management plan for the construction period which has the purpose of identifying all requirements necessary so that project construction does not impede normal road operations (BEP II 2002a, p.7.4-12).

The applicant has stated that oversized and overweight deliveries would be by railroad train, offloading near Commercial Street in Blythe between Hobsonway and Barnard Street onto trucks, which would proceed west on Hobsonway or I-10 to the project site (BEP II 2002a, p. 7.4-10). Staff has recently learned in communication with City staff that Hobsonway cannot be used for these oversized/heavy loads because of the new median islands being constructed on Hobsonway; the City is also concerned about potential damage to Hobsonway (Wellman 2003b). Staff is uncertain how these loads would be moved from the railroad offloading point to the freeway while taking into account the above City concerns. City staff believes that an adequate alternative route is available (Bennett). Before staff can complete the Traffic and Transportation section of the FSA, the applicant must submit an alternative route for oversize and overweight loads that avoids use of Hobsonway.

Emergency Access

The Riverside County Fire Department would serve BEP II from any of four stations in the vicinity of the BEP II site; the station nearest the BEP II site is about 1 mile west on Hobsonway (Zimmerman). The County Fire Department has a fulltime staff, and can call on Countywide and State resources as the need arises (Zimmerman). The Blythe Ambulance Service would provide emergency medical service. The nearest hospital is Palo Verde Hospital in Blythe, about 5 miles from the project site. Ambulance response time to BEP II would be from 7 to 10 minutes (Watkins). Access for fire and medical services would be along Hobsonway to the site (Zimmerman and Watkins).

Operational Phase

Commute Traffic

Operation of the generating plant would require a labor force of 5 full-time employees (BEP II 2002a, p. 7.4-15). A worst case scenario assumes that each employee would drive a separate vehicle to work and that they would make one round trip from home to work per day, generating approximately 10 vehicle trips per day. Adequate parking would be made available for employees on an on-site paved lot. Staff assumes that the majority of the permanent workforce would reside in the greater Blythe area and their preferred route to work would be east along I-10 to Mesa Drive, then east on Hobsonway to Buck Boulevard, and west on Hobsonway to Buck Boulevard or west on I-10 to the SR 78 interchange and west on Hobsonway to Buck Boulevard. BEP II operations-related traffic impacts are considered minimal, representing less than 1 percent of existing AADT on I-10.

Truck Traffic

The applicant has estimated that there would be two truck round trips to the site daily, or 4 trips total, during plant operations (BEP II 2003a, p. 7.4-16). This addition to daily traffic will not significantly affect LOS levels.

Transport of Hazardous Materials and Waste

The transportation and handling of hazardous substances associated with the project can increase roadway hazard potential. Impacts associated with hazardous material transport to the facility can be mitigated to a level of insignificance by compliance with existing federal and State standards established to regulate the transportation of Hazardous Substances (see staff proposed Condition of Certification **TRANS-4**).

The California Department of Motor Vehicles specifically licenses all drivers who carry hazardous materials. Drivers are also required to check for weight limits and conduct periodic brake inspections. Commercial truck operators handling hazardous materials are also required to take instruction in first aid and procedures on handling hazardous waste spills. Drivers transporting hazardous waste are required to carry a manifest, which is available for review by the California Highway Patrol at inspection stations along major highways and interstates.

The California Vehicle Code and the Streets and Highways Code (Sections 31600 through 34510) ensure that the transportation and handling of hazardous materials are done in a manner that protects public safety. Enforcement of these statutes is under the jurisdiction of the California Highway Patrol.

The applicant has indicated that the transportation of hazardous materials to and from the site would be conducted in accordance with all applicable LORS for the handling and transportation of hazardous materials.

The handling and disposal of hazardous substances are also addressed in the **WASTE MANAGEMENT, WORKERS SAFETY AND FIRE PROTECTION** and **HAZARDOUS MATERIALS** sections of this report.

Hazards due to Project Design Features

Air Traffic Patterns and Airport Operations

The BEP I project owner has stated that the thermal and visual plumes caused by BEP will not have an impact on aviation safety (Blythe Energy, LLC). However, concerns have been raised regarding the hazards to aircraft using Blythe Airport caused by thermal and visual water vapor plumes from both the BEP I and BEP II power plants. (See Wolfe 2003a, b, & c). The Commission staff contacted the FAA, whose staff sent an e-mail stating the need for a Notice to Airmen (NOTAM) regarding the existing power plant's proximity to the airport (Garcia 2003a and b). To date staff is not aware of any notice being published. Staff has also asked the Caltrans Aeronautics Division staff to review the Wolfe letters regarding potential hazards related to thermal and visible plumes. Caltrans Aeronautics staff responded in a letter of August 29, 2003 (Caltrans 2003), which stated that on August 19, 2003 one of their pilots had flown over the BEP I plant and BEP II site, and the airport runway area. This letter noted that Caltrans will not be able to reach any conclusions regarding aviation safety hazards until a second flight and reevaluation is conducted in December, 2003, or January, 2004 when visible and thermal plumes are most likely to occur (i.e., during cold, clear winter morning conditions). Caltrans staff also noted the possibility of significant direct and cumulative impacts. The **TRAFFIC and TRANSPORTATION** section of the BEP II FSA cannot be completed until there is sufficient information to allow a thorough analysis of the impact of BEP II on airport traffic safety.

A Commission consultant performed a project visible plumes and ground fogging analysis (Walters 2003a and 2003b). Visible plume formation would occur mainly during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. On an annual basis, during daylight hours with no rain or fog, cooling tower plumes would be expected to occur approximately 6% of the time. For HRSGs no visible steam plumes were predicted to occur. Because the frequency of ground fogging caused by project plumes would be very low (only a few hours of ground fog during the three years modeled by the analysis) ground fogging appears not to be significant, and so would not have a significant impact on ground transportation. Staff is planning a thermal plume study and further study of potential visual plume impact to be conducted by consultants. These studies will include analysis of potential direct and cumulative impacts of BEP I AND BEP II. The receipt of these studies is necessary for the completion of the Traffic and Transportation FSA.
The City of Blythe Plan Review Committee has listed the following air traffic safety requirements for BEP II (Petritz 2003a):

- If discharge from the cooling towers could under any circumstances form a visible plume, then the current best available technology shall be utilized to disperse such a plume (or plumes).
- Modeling should be done to determine if the stacks for the subject project (as shown on the preliminary site plan) would be immediately below the turning point for VFR traffic. If this is the case, then the applicant developer should consider re-aligning the stacks.

There is a remote chance of an accidental release from the ammonia refrigeration system as the result of an aircraft crash at BEP II. Staff has determined that the probability of such an event is 1 in 10,000,000 (See the **Hazardous Materials Management** section of this document for further analysis).

Condition **TRANS-8** would require the applicant to comply with the ALUC's proposed conditions relevant to traffic and transportation. See the **LAND USE** section of this Staff Assessment for further discussion of the ALUC's determination.

Project Height in Relation to Aviation Safety

The east edge of the primary airport runway (Runway 8-26) is approximately one mile west of the BEP II site. The end of Runway 8-26 is located at 393 feet above mean sea level (MSL). The BEP II site is approximately 335 feet above MSL. When constructed, the power plant heat recovery steam generator (HRSG) stacks will be 130 feet high, the maximum height of the project. The stacks are estimated to be 72 feet above the level of the runway. When using the lowest Instrument Landing System (ILS) angle (2.9 degrees) for Runway 8-26, the height of the aircraft over the stacks could be about 168 feet (BEP II 2002a, p.7.4-8). The ILS approach to Runway 8-26 has not been approved by the FAA (Coffman 1992, p. 2-3). The ILS is a landing system for flight training. Non-training flights fly under Visual Flight Rules (VFR), and comprise two-thirds of all flights at Blythe Airport (Wolfe 2003c). However, if the transmission towers between the BEP II integration substation and the Buck Boulevard substation are double circuited, they would be approximately 145 feet in height (BEP II 2003, p. 41), and would be the tallest project elements rather than the HRSG stacks.

In response to the applicant's applications for the two HRSG stacks, the FAA has made determinations of no hazard to air navigation related to the stacks. This evaluation, related to the project HRSG stack height, found that the proposed structure would not exceed obstruction standards and would not be a hazard to air navigation. Based on this evaluation marking and lighting would be necessary for aviation safety in accordance with FAA requirements (BEP II, 2002a Appendix 7.4, FAA Determinations of No Hazard to Air Navigation). This project hazard evaluation process by the FAA does not include potential aviation safety and compatibility impacts related to thermal and visible plumes. Proposed condition **TRANS-7** mandates the implementation of the FAA's marking and lighting requirements. If the project design is changed to include elements with greater height than the HRSG stacks, such as the possible 145 feet-tall transmission towers noted above, staff cannot complete the Traffic and Transportation section of the FSA until receipt of FAA evaluation of such project elements.

Linear Facilities

The water line for BEP II will interconnect on-site with existing BEP I transmission; the natural gas pipeline may also connect with the on-site existing BEP I pipeline (BEP II 2002a, p. 2-1).If another configuration for natural gas pipeline connection is chosen, staff would have to assess the impact of this connection. The BEP II electrical connection would be to the Buck Boulevard substation located in the northwest corner of the Project site, which would connect with the Imperial Irrigation District's (IID) proposed 118-mile transmission line. If all linear facilities interconnect on-site as presently planned, linear facilities construction would not cause significant impact on local and regional roads and highways.

CUMULATIVE IMPACTS

POTENTIAL AVIATION SAFETY IMPACTS

As discussed above under Airport Operations, there are concerns regarding the impact of BEP I and BEP II visual water vapor plumes and thermal plumes on air traffic safety that must be assessed. It is possible that the combined impact of visual and thermal plumes from the two plants would create a cumulative effect on air traffic safety that would be greater than the added separate impact of each plant. These concerns must be assessed before the Traffic and Transportation FSA can be completed. Caltrans Aeronautics staff concurs that this possibility is a concern warranting further investigation (Caltrans 2003). Staff's planned thermal and visual plume studies will include analysis of potential cumulative impacts of BEP I AND BEP II.

CALTRANS PROJECTS

The analysis of the available capacity of the regional highways and local roads described in this section shows that the regional transportation system serving the BEP

II area (along the potentially affected highways) is operating at very efficient levels of service with significant reserve capacity. The three primary highways and the primary local arterial operate at LOS A.

According to Caltrans staff there will be several minor Caltrans construction and maintenance projects performed on the three highways (I-10, U.S. 95, and SR 78) in the vicinity of the BEP II site that would be used by BEP II construction trucks, and one major project, implemented during timeframes that could fall within the BEP II construction timeframe (Roberts). Examples of the minor projects are replacement of a railroad crossing, drainage improvements, and landscaping. The major project is U.S 95 shoulder widening and rehabilitation .6 mile north of C Canal in Blythe (Roberts). **TRANS-1** would require that the project owner prepare a project construction traffic control plan in consultation with affected local jurisdictions and Caltrans. Because these three highways are now at LOS A, with implementation of **TRANS-1** staff expects that these Caltrans projects would not be a cumulative impact in combination with BEP II construction.

DEVELOPMENT PROJECTS

The Blythe Airport Industrial Park site is located on airport land a mile west of the power plant. Development of this industrial park could create potential localized impacts at the I-10/Mesa Drive interchange. However, presently there are no pending applications for development of any portions of this industrial site (Hull).

The City of Blythe intends to serve the Mesa Verde community by connecting it with the airport water and sewer lines within the next 12 to 18 months; the Mesa Drive interchange has sufficient capacity for both these upgrades and BEP II construction truck traffic (Hull).

There is a trucking company construction project planned for the south side of Hobsonway between Buck Road and Neighbors Boulevard; this project would not begin construction within the next 12 months (Hull). The structures that would comprise this project would consist of 117,840 square feet of floor space (Wellman 2003c). Given Hobsonway's present traffic level of LOS A, and with the implementation of **TRANS-1,** staff does not believe that this project would be a significant cumulative impact.

PROPOSED IMPERIAL IRRIGATION DISTRICT (IID) TRANSMISSION LINE

The IID has proposed to construct a new 118-mile transmission line (the Desert Southwest Transmission Line Project) from the Western Buck Boulevard Substation to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs. BEP II would connect with the Buck Boulevard substation, which would connect with this new transmission line. The IID's Proposed Project would be constructed within an existing transmission line corridor. The Proposed Projec generally would be constructed parallel to existing major roads, and a majority of dirt access roads already exist (BLM/IID p. 3.10-1). The Proposed Project would cross various highways and local roads. IID project construction trucks may use highways that would also be used by BEP II construction trucks, but staff assumes that given the present low traffic volume on these roads (see BLM/IID Table 3.10-1, p. 3.10-4), there would be no cumulative impact with BEP II construction.

Given the information we currently have, staff is not aware of any cumulative impact that the IID's Proposed Project could have on airports in the region and aviation safety.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

The Applicant has stated its intention to comply with all applicable LORS. However, assessment of LORS consistency depends on further information regarding impact on local roads, CLUP consistency, and airport flight traffic safety.

LOCAL

The previously described City General Plan Circulation Element's relevant goals, objectives, and policies are discussed below:

Transportation Demand Management Goal: To promote the use of non-single occupant modes of transportation, and to shift trips out of current peak periods.

Objective 3.0 The City shall encourage employers to provide alternative work weeks and flextime sufficient to reduce peak period trips by 10%.
The following policy is in support of Objective 3.0:

Policy 3.1: The City shall encourage employers to provide 4 day-40 hour and 9 day-80 hour work weeks, and/or provide start/end times outside of the 6-8 a.m. and 4-6 p.m. peak periods of traffic.

Discussion: The Blythe II Traffic Management Plan does not contain a plan for alternative work schedules and therefore is in conflict with this policy. Proposed condition of certification **TRAFFIC and TRANSPORTATION-1** would encourage that the project's Construction Traffic Control Plan address the need for construction work hours and arrival/departure times outside of peak traffic periods.

Policy 11 Provide and maintain roadway intersection operations at Level of Service (LOS) D or better at peak traffic volumes for all segments of the City's circulation system.

Discussion: Since project construction and operations traffic would not cause peak traffic volumes to be worse than LOS D, the project is not in conflict with this policy.

Other conditions would ensure compliance with federal, State, and local LORS:

TRANS-3 Requires compliance with requirements regarding encroachment into the public right-of-way.

TRANS-5 Requires compliance with parking standards.

TRANS-6 Requires project owner repair of public rights-of-way damaged during construction.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and Census 1990 information that shows the low-income population is less than fifty percent within the same radius. Based on the traffic and transportation analysis, staff has identified possible unmitigated significant direct and cumulative impacts resulting from the operation of the project that could affect the safety of air traffic. However, staff has no data demonstrating that minority and low-income populations would be disproportionately impacted, and therefore there are no traffic and transportation environmental justice issues related to this project.

FACILITY CLOSURE

There are at least three circumstances in which a facility closure can take place; planned closure, unexpected temporary closure and unexpected permanent closure. The minimum design life of the power plant is expected to be 30 years. At least 12 months prior to the proposed decommissioning, the applicant shall prepare a closure plan for submission to the Energy Commission for review and action. At the time of closure all then-applicable LORS will be identified and the closure plan will address how to comply with these LORS. The effects of closure for the BEP II Energy power plant on traffic and transportation will be similar to those discussed for the construction of the project. Closure will create traffic levels that are similar in intensity and duration to those expected during facility construction.

Unexpected temporary closure occurs when the facility is closed suddenly or unexpectedly, on a short-term basis, due to unforeseen circumstances such as a natural disaster, or an emergency. From the perspective of traffic and transportation issues, in the event of temporary facility closure, the applicant would have to comply with all applicable policies contained in the LORS section of this report regarding transportation permits for hazardous materials and equipment.

Unexpected permanent closure occurs if the project owner closes the facility suddenly or unexpectedly, on a permanent basis. If unexpected closure occurs, the owner remains accountable for implementing the on-site contingency plan. Unexpected closure can occur when the project owner is unable to implement the contingency plan, and the project is essentially abandoned. Staff assumes that the facility will either remain idle until such time that new ownership is established, or dismantling of the facility will occur. In any event, the owner will have to secure applicable transportation permits to satisfy the LORS requirements as stated in this report.

In the event of temporary closure, the effects on traffic and transportation would be similar to those for normal operation of the power plant facility. In the event of permanent closure, the effects would be similar to those associated with project construction. Permanent closure will involve a peak work period with commuter traffic. In either instance, the roadway systems within the vicinity of the project should be able to handle traffic without significantly affecting the current level of service of the area.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

On April 18, 2002 the Commission received a letter dated April 16, 2002 from R. Austin Wiswell, Chief, Division of Aeronautics, Caltrans addressed to the project's Project Manager (Caltrans 2002a). The letter discusses several minor discrepancies in the AFC, and the possible impact of waterfowl attractants caused by the project. This letter refers to and includes as an attachment a letter dated February 28, 2002 from Sandy Hesnard, Aviation Environmental Planner, Caltrans to Jennifer Wellman, Development Services Department, City of Blythe. This letter discusses project inconsistency with the CLUP, concerns regarding possible penetration of navigable airspace, and the potential project impact as a wildlife attractant. Staff has discussed the above concerns and other concerns relating to visual and thermal plumes with Caltrans Aeronautics staff.

On July 26, 2002 the Commission received a second letter with the same date from Mr. Wiswell to the Energy Facilities Licensing Program (Caltrans 2002b). The letter discusses the same minor discrepancies in the AFC referred to in the first letter, and also discusses Caltrans Division of Aeronautics LORS relevant to BEP II. Staff has included these LORS in the PSA.

On August 29, 2003, the Energy Commission received a letter dated August 28, 2003 from Mark Aldridge, Aviation Safety Officer, Caltrans Division of Aeronautics, to Energy Commission staff describing the results of a flight evaluation of the effects on aviation of the thermal discharges of BEP (Caltrans 2003c). The report states that no turbulence or visual plumes were experienced during the flight evaluation, which took place on August 10, 2003, but to accurately assess the effects of the energy plant on aviation, an evaluation must be conducted in December or January. This reevaluation will also consider the effect that BEP II thermal and visual plumes would have on aviation safety. This letter recommends that the cumulative effect of plumes from BEP and BEP II be evaluated by a firm with the ability to model expected thermal as well as visual steam plumes. The letter states: "It is imperative that we ascertain the compatibility of the two power plants operating in close proximity to the airport before Plant #2 is built." Staff is continuing to assess the impact of BEP II thermal and visual plumes on aviation safety, and is working to obtain the plume modeling data recommended by Caltrans.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

1. The project would be consistent with the circulation elements of the County and City General Plans. The project would not have a significant impact on the local and regional road/highway network. During the construction phase, local roadway and highway demand resulting from the daily movement of workers and materials would

not increase beyond significance thresholds established by local and state authorities. During the operational phase, increased roadway demand resulting from the daily movement of workers and materials would be minimal.

2. The aviation agencies (i.e. Caltrans Aeronautics, FAA, and the ALUC) are working with staff to assess the potential direct and cumulative impact of visual and thermal plumes from BEP and BEP II.

3. The FAA has made determinations of no hazard for this project's exhaust stacks with conditions. The transmission towers may be taller than the HRSG stacks, requiring a reevaluation by FAA of its determination of no hazard to air navigation.

4. There would be transportation of hazardous materials during construction and operation. There is good road access for the transportation of hazardous materials. With implementation of the proposed conditions of certification, potential problems would not exceed significance thresholds established by the Highway Patrol.
5. The City's recent renovation of Hobsonway does not allow for oversize and overweight loads to be transported on Hobsonway from the railroad offloading point near Commercial street.
6. The City of Blythe General Plan's Circulation Element contains an objective requiring the City to encourage employers to provide alternative work weeks and flextime. The Applicant's Construction Traffic Control Plan does not contain such provisions, and there is no operation period plan that includes such provisions.

RECOMMENDATION

Staff will not be able to complete the Traffic and Transportation section of the Staff Assessment until receipt of:

∉ adequate assessment by the applicant, aviation agencies, and/or consultants of the impact of visual and thermal plumes, including the cumulative impact of BEP I and BEP II, on airport traffic safety;

∉ FAA evaluation as necessary of project elements that are taller than the HRSG stacks; and

∉ Description of an alternative route for oversize and overweight loads that avoids use of Hobsonway.

If the Energy Commission certifies the Blythe Energy Project Phase II, staff recommends that the Commission adopt staff's proposed conditions of certification. With further information staff may recommend additional conditions.

CONDITIONS OF CERTIFICATION

TRANS-1 The project owner should encourage the development of a construction traffic control plan that limits peak hour construction-period truck and commute traffic in coordination with the City of Blythe Public Works Department and the

County of Riverside Public Works Department. The project owner should also consult with City of Blythe and County of Riverside staff dealing with traffic regulation enforcement, and the California Highway Patrol to develop measures intended to minimize speeding by construction-related vehicles. Specifically, the overall traffic control plan should include the following:

- Verbal and written instructions to construction workers and related suppliers, intended to raise awareness of existing speeding problems on area roadways.
- The EPC and major subcontractors should develop and implement a construction employee carpool program;
- The worker education and shift scheduling, maximize worker commute trips during off-peak hours (off-peak hours are (1) before 6:00 AM; (2) between 9:00 AM and 4:00 PM; and (3) after 6:00 PM); or the hours agreed to by the CPM.
- Schedule heavy vehicle equipment and building material deliveries as well as the movement of materials and equipment to the site, including the adjacent laydown area to occur during off-peak hours (off-peak hours are (1) before 6:00 AM; (2) between 9:00 AM and 4:00 PM; and (3) after 6:00 PM); or any limited deviations from this time frame, with CPM approval, and options for continuation of this program into the operation period pursuant to City Circulation Element Objective 3.0; or hours agreed to by the CPM.

  The construction traffic control and transportation demand management program should also include the following restrictions on construction traffic addressing the following issues for linear facilities:

  - Signing, lighting, and traffic control device placement;
  - Temporary travel lane closures and potential need for flagmen;
  - Maintaining access to adjacent residential and commercial properties; and
  - Emergency access.

Verification: At least 60 days prior to start of mobilization, the project owner shall provide to the City of Blythe, the County of Riverside, and the California Highway Patrol for review and comment, and to the CPM for review and approval, a copy of their construction traffic control plan

TRANS-2 The project owner shall comply with California Department of Transportation (Caltrans) and other affected jurisdictions' limitations on vehicle sizes and weights. In addition, the project owner or their contractor shall obtain necessary transportation permits from Caltrans and all relevant jurisdictions for roadway use.

Verification: In the Monthly Compliance Reports, the project owner shall submit copies of any oversize and overweight transportation permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

TRANS-3 The project owner shall ensure compliance with Caltrans and other relevant jurisdictions' limitations for encroachment into public rights-of-way, and shall obtain necessary encroachment permits from Caltrans and all relevant jurisdictions.

Verification: In the Monthly Compliance Reports, the project owner shall submit copies of any encroachment permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

TRANS-4 The project owner shall ensure that permits and/or licenses are secured from the California Highway Patrol and Caltrans for the transport of all hazardous materials, and that all federal and State regulations for the transport of hazardous materials are observed.

Verification: The project owner shall include in its Monthly Compliance Reports during construction and Annual Compliance Reports during operations copies of all permits and licenses acquired by the project owner concerning the transport of hazardous materials.

TRANS-5 Prior to the construction of the power plant and all related facilities, the project owner shall develop a parking and staging plan for all phases of project construction, to enforce a policy that all project related parking occurs on-site or in designated off-site parking areas.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit the plan to the City of Blythe Public Works staff for review and comment, and to the CPM for review and approval. The material submitted to the CPM shall include documentation of the City's review and comments. Monthly Compliance Reports submitted to the CPM shall describe the project owner's actions to ensure that this condition is being met.

TRANS-6 Prior to the beginning of site mobilization activities, the project owner shall prepare a road mitigation plan for any roads affected by oversize or overweight vehicles to the County of Riverside and the City of Blythe Public Works Departments, and the CPM. The intent of this plan is to insure that any roads affected by oversize or overweight vehicles will be repaired and reconstructed to original or as near original condition as possible. This plan shall:

- Document the pre-construction condition of the roads, prior to the start of site mobilization, the project owner shall provide to the CPM photographs or videotape of the roads affected in the region of the site.
- Document any portions of roads that may be inadequate to accommodate oversize or large construction vehicles, and complete remediation measures that are necessary;
- Provide appropriate bonding or other assurances to insure that any damage to a road due to construction activity will be remedied by the project owner;

- Relocate utility poles if necessary, to insure that adequate clear zones are established along the property frontage; and
- Reconstruct portions of roads that are affected by the installation of underground utilities.

Verification: At least 90 days prior to the start of site mobilization, the project owner shall submit a road mitigation plan focused on restoring the roads to their pre-project condition to the County of Riverside and the City of Blythe for review and comment and to the CPM for review and approval.

TRANS-7 The HRSG stacks and any other project structures (e.g., transmission line towers, and cooling towers or other cooling structures) with the potential to obstruct navigable air space, as determined by the Federal Aviation Administration (FAA), shall have the lighting and markings required by the FAA so that the stacks and other project structures do not create a hazard to air navigation.

The project owner shall submit to the FAA Form 7460-1, Notice of Proposed Construction or Alteration and supporting documents on how the project plans to comply with stack (and other structures, if needed) lighting and marking requirements imposed by the FAA.

Verification: At least 30 days prior to the start of construction, the project owner shall provide copies of the FAA Form 7460-1 with copies of the FAA response to Form 7460-1, to the CPM and the City of Blythe Planning Department.

TRANS-8 The project owner shall comply with the following:

- Any use is prohibited which would direct a steady light or flashing light of red, white, green, or amber colors associated with airport operations toward an aircraft engaged in an initial straight climb following takeoff or toward an aircraft engaged in a straight final approach toward a landing at an airport, other than an FAA-approved navigational signal light or visual approach slope indicator.
- Any use is prohibited which would cause sunlight to be reflected towards an aircraft engaged in an initial straight climb following takeoff or towards an aircraft engaged in a straight final approach towards a landing at an airport.

Verification: 30 days before construction start the project owner shall submit to the CPM documentation of compliance with the above requirements

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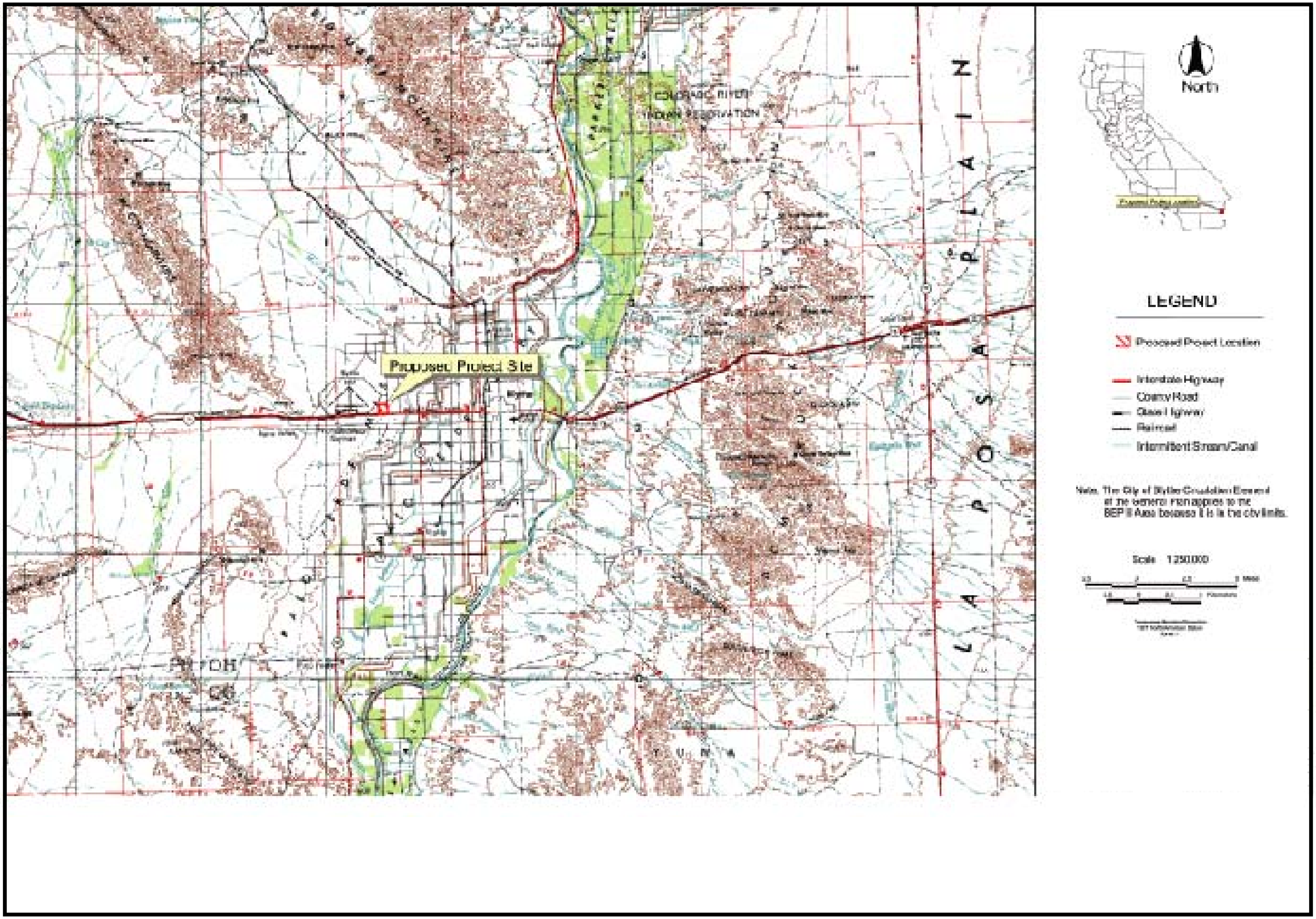
TRAFFIC AND TRANSPORTATION - FIGURE 1

Blythe Energy Project Phase II - Project Site Area

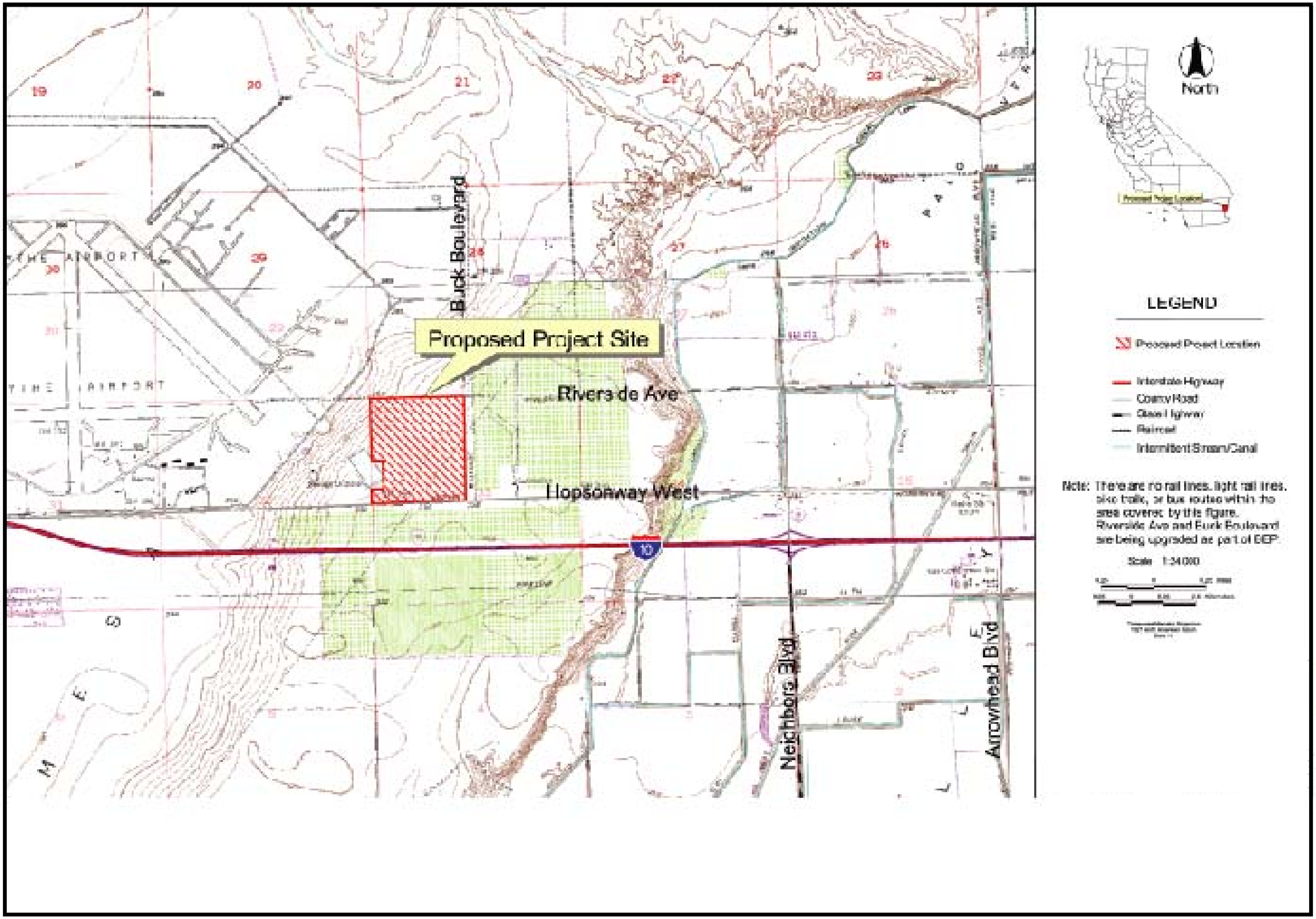


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: BEP II 2002a, Figure 7.4-1

TRAFFIC AND TRANSPORTATION - FIGURE 2

Blythe Energy Project Phase II - Project Site Vicinity



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: BEP II 2002a, Figure 7.4-2

TRANSMISSION LINE SAFETY AND NUISANCE

Obed Odoemelam, Ph.D.

INTRODUCTION

The proposed Blythe Energy Project Phase II (BEP II) would be electrically connected to the existing Western Area Power Administration (Western) 161/500 kV Buck Boulevard Substation located at the northeastern corner of the Blythe Energy Project (BEP I) previously permitted by the California Energy Commission. As with BEP I, the energy from the proposed BEP II would be transmitted from the Buck Boulevard Substation to the area's Western power grid through the same 161 kV lines to be used for the permitted BEP I. A new interconnection to the Devers Substation using a new 118-mile 500kV single-circuit transmission line would also be made. This new 118-mile transmission line is not part of BEP II, and is therefore only evaluated here in terms of cumulative impacts. The connection between BEP II's generators and the Western Buck Boulevard Substation would be made using a new overhead 2500-foot 500 kV line to be located entirely within the BEP I/BEP II site boundaries.

The purpose of this staff analysis is to assess the proposed transmission plan for its adequacy to conduct the generated energy without the health and safety impacts possible from the current flow to be involved. If these line impacts were to be as staff expects for the total amount of power to be transmitted, staff would regard the proposed line designs and operational plan as reflecting compliance with the applicable health and safety laws, ordinances, regulations and standards (LORS). If the lines were to be much higher than appropriate, staff could recommend mitigation before the BEP II energy is introduced into the area's power grid. Staff's analysis focuses on the following issues:

- aviation safety;
- interference with radio-frequency communication;
- audible noise;
- fire hazards;
- hazardous shocks;
- nuisance shocks; and
- electric and magnetic field (EMF) exposure.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Discussed below by subject area are design-related LORS applicable to the physical impacts of the existing and new overhead transmission lines to be used. There presently are no local laws or regulations specifically aimed at those aspects of electric line structure or dimensions that influence the magnitude of the impacts noted above. The only such regulations are local requirements for such lines to be located underground in new housing developments because of the potential for visual impacts on the landscape. Such requirements are not aimed against any specific health effects.

AVIATION SAFETY

Any hazard to area aircraft would relate to the potential for collision in the navigable air space. The applicable federal LORS discussed below are intended to ensure the distance and visibility necessary to prevent such collisions.

Federal

- Title 14, Code of Federal Regulations (CFR), Part 77, "Objects Affecting the Navigation Space." Provisions of these regulations specify the criteria used by the Federal Aviation Administration (FAA) for determining whether a "Notice of Proposed Construction or Alteration" is required for potential obstruction hazards. The need for such a notice depends on factors related to the height of a structure, the slope of an imaginary surface from the end of nearby runways to the top of the structure, and the length of the runway involved. Such notification allows the FAA to ensure that all structures are located to avoid the aviation hazards of concern.
- FAA Advisory Circular (AC) No. 70/460-2H, "Proposed Construction and or Alteration of Objects that May Affect the Navigation Space." This circular informs each proponent of a project that could pose an aviation hazard of the need to file the "Notice of Proposed Construction or Alteration" (Form 7640) with the FAA.
- FAA AC No. 70/460-1G, "Obstruction Marking and Lighting." This circular describes the FAA standards for marking and lighting objects that may pose a navigation hazard as established using the criteria in Title 14, Part 77 of the CFR.

INTERFERENCE WITH RADIO-FREQUENCY COMMUNICATION

Transmission line-related radio-frequency interference is one of the indirect effects of line operation produced by the physical interactions of line electric fields. Since electric fields are unable to penetrate most materials, including the ground, such interference and other electric field effects are not associated with underground lines. The level of any such interference usually depends on the magnitude of the electric fields involved. Because of this, the potential for perception can be assessed from field strength estimates obtained for the line design. The interference is due to the radio noise produced by the action of the electric fields on the surface of the energized conductor. The process involved is known as corona discharge, but is referred to as spark gap electric discharge when it occurs within gaps between the conductor and insulators or metal fittings. When generated, such noise manifests itself as the perceivable interference with radio or television signal reception or interference with other forms of radio-frequency communication. Since the level of interference depends on factors such as line voltage, distance from the line to the receiving device, orientation of the antenna, signal level, line configuration, and weather conditions, maximum interference levels are not specified as design criteria for modern transmission lines. The following regulations are intended to ensure that such lines are located away from areas of potential interference and that any interference is mitigated whenever it occurs.

Federal

∉ Federal Communications Commission (FCC) regulations in Title 47 CFR, Section 15.25. Provisions of these regulations prohibit operation of any devices producing force fields, which interfere with radio communications, even if (as with transmission lines) such devices are not intentionally designed to produce radio-frequency energy. For such lines, interference is minimized through the use of specific low-corona cables as conductors. The FCC requires each line operator to mitigate all complaints about interference on a case-specific basis.

State

∉ General Order 52 (GO-52), California Public Utilities Commission (CPUC). Provisions of this order govern the construction and operation of power and communications lines and specifically deal with measures to prevent or mitigate inductive interference.

Several design and maintenance options are available for minimizing these induced fields. When incorporated into the line design and operation, such measures also serve to reduce the line-related audible noise discussed below.

AUDIBLE NOISE

Industry Standards

There are no design-specific federal or state regulations that limit the audible noise from transmission lines. As with radio noise, such noise is limited instead through design, construction, or maintenance practices established from industry research and experience. These practices are effective and do not significantly impact line safety, efficiency, maintainability, and reliability. All modern overhead high-voltage lines are designed to assure compliance with such noise limits. As with radio-frequency noise, such noise usually results from the action of the electric field at the surface of the line conductor and could be perceived as a characteristic crackling, frying or hissing sound, or hum, especially in wet weather. Since the noise level depends on the strength of the line electric field, the potential for perception can be assessed from estimates of the field strengths expected during operation. Such noise is usually generated during rainfall, but mainly from overhead lines of 345 kV or higher. Research by the Electric Power Research Institute (EPRI 1982) has validated this by showing the fair-weather audible noise from modern transmission lines to be generally indistinguishable from background noise at the edge of a 100-foot right-of-way. Underground lines do not generate such noise, since they cannot produce the responsible surface-level electric fields.

FIRE HAZARDS

The fire hazards addressed through the following regulations are those that could be caused by sparks from conductors of overhead lines, or that could result from direct contact between the line and nearby trees and other combustible objects.

State

- General Order 95 (GO-95), CPUC. “Rules for Overhead Electric Line Construction” specify tree-trimming criteria to minimize the potential for power line-related fires.
- Title 14, California Code of Regulations, Section 1250. “Fire Prevention Standards for Electric Utilities” specify utility-related measures for fire prevention.

HAZARDOUS SHOCKS

The hazardous shocks addressed through the following regulations and standards are those from direct or indirect contact between an individual and the energized line, whether overhead or underground. Such shocks are capable of serious physiological harm or death and remain a driving force in the design and operation of transmission and other high-voltage lines.

State

- GO-95, CPUC. “Rules for Overhead Line Construction” specify uniform statewide requirements for overhead line construction regarding ground clearance, grounding, maintenance, and inspection. Implementing these requirements ensures the safety of the general public and line workers.
- Title 8, California Code of Regulations (CCR), Sections 2700 et seq.: “High Voltage Electric Safety Orders” establish essential requirements and minimum standards for safely installing, operating, working around, and maintaining electrical installations and equipment

Industrial Standards

No design-specific federal regulations have been established to prevent hazardous shocks from overhead power lines. Safety is assured within the industry from compliance with the requirements in the National Electrical Safety Code, Part 2: Safety Rules for Overhead Lines. These provisions specify the minimum national safe operating clearances applicable in areas where the line might be accessible to the public. They are intended to minimize the potential for direct or indirect contact with the energized line.

NUISANCE SHOCKS

Industry Standards

Nuisance shocks are caused by current flow at levels generally incapable of causing significant physiological harm. They result mostly from direct contact with metal objects electrically charged by fields from the energized line. Such electric charges are induced in different ways by the line electric and magnetic fields. There are no design-specific federal or state regulations to limit nuisance shocks in the transmission line environment. For modern overhead high-voltage lines, such shocks are effectively minimized through grounding procedures specified in the National Electrical Safety Code (NESC) and the joint guidelines of the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE). As with the proposed overhead lines, the applicant is responsible in all cases for ensuring compliance with these grounding-related practices within the right-of-way.

ELECTRIC AND MAGNETIC FIELD EXPOSURE

The possibility of deleterious health effects from EMF exposure has increased public concern in recent years about living near high-voltage lines. Both fields occur together whenever electricity flows, hence the general practice of describing exposure to them together as EMF exposure. The available evidence as evaluated by the CPUC, other regulatory agencies, and staff, has not established that such fields pose a significant health hazard. However, staff considers it important, as does the CPUC, to note that while such a hazard has not been established from the available evidence, the same evidence does not serve as proof of a definite lack of a hazard. Staff, therefore, considers it appropriate, in light of present uncertainty, to recommend feasible reduction of such fields without affecting safety, efficiency, reliability, and maintainability.

While there is considerable uncertainty about EMF health effects, the following facts have been established from the available information and have been used to establish existing policies:

- Any exposure-related health risk to the exposed individual will likely be small.
- The most biologically significant patterns (e.g., high-level, short-term versus low-level, long-term) of exposures have not been established.
- Most health concerns are about the magnetic field.
- The measures employed for such field reduction can affect line safety, reliability, efficiency, and maintainability, depending on the type and extent of such measures.

State

In California, the CPUC (which regulates the installation and operation of high-voltage lines in California) has determined that only no-cost or low-cost measures are presently justified in any effort to reduce power line fields below levels existing before the present health concern arose. The CPUC has further determined that such reduction should be made only in connection with new or modified lines. It requires each electric utility within its jurisdiction to establish EMF-reducing measures and incorporate such measures into the designs for all new or upgraded power lines and related facilities within their respective service areas. The CPUC further established specific limits on the resources to be used in each case for field reduction. Such limitations were intended by the CPUC to apply to the cost of any redesign to reduce field strength or relocation to reduce exposure. The other utilities, which are not within the jurisdiction of the CPUC, voluntarily comply with these CPUC requirements by designing their lines in keeping with the guidelines of the major area utility. The service utility in this case is Western. This field reduction policy of the CPUC resulted from assessments made to implement CPUC Decision 93-11-013.

In keeping with this CPUC policy, staff requires each applicant to show how each proposed overhead line would be designed to comply with the EMF-reducing design guidelines applicable to the utility service area involved. For existing lines, staff assesses compliance by comparing the fields with fields from compliant lines of the same voltage and current-carrying capacity. The available reducing measures can impact line operation if applied without appropriate regard for environmental and other local factors bearing on safety, reliability, efficiency, and maintainability. Therefore, it is up to each applicant to ensure that such measures are applied to an extent that does not significantly affect line operation and safety. It is the extent of such applications that is reflected by the ground-level field strengths as measured during operation. These field strengths can be estimated for any given design using established procedures and can be verified from actual measurements during operations. Estimates are specified for a height of one meter above the ground, in units of kilovolts per meter (kV/m), for the electric field, and milligauss (mG) for the companion magnetic field. Their magnitude depends on line voltage (in the case of electric fields), the geometry of the structures, degree of cancellation from nearby conductors, distance between conductors and, in the case of magnetic fields, amount of current in the line.

Since each new or modified line in California is currently required to be designed according to the EMF-reducing guidelines of the utility in the service area involved, its fields are required under existing CPUC policies to be similar to fields from similar lines in that service area. It is for this reason that the permitted BEP I lines were designed to incorporate Western's field strength-reducing guidelines, as would the new on-site 500kV lines that would connect BEP II's generators to the Buck Boulevard Substation. Compliance with these Western guidelines would constitute compliance with the CPUC requirements for line field management. Staff recommends a specific condition of certification (**TLSN-1**) to ensure implementation of the design measures necessary for these on-site lines.

Industrial Standards

There are no health-based federal regulations or industry codes specifying limits on the strengths of fields from power lines. However, the federal government continues to conduct and encourage research necessary for an appropriate policy on the EMF health issue.

In the face of the present uncertainty, several states have opted for design-driven regulations ensuring that fields from new lines are generally similar to those from existing lines. Some states (such as Florida, Minnesota, New Jersey, New York, and Montana) have set specific environmental limits on one or both fields in this regard. These limits are, however, not based on any specific health effects. Most regulatory agencies believe, as does staff, that health-based limits are inappropriate at this time and that the present knowledge of the issue does not justify any retrofit of existing lines.

Before the present health-based concern developed, measures to reduce field effects from power line operations were mostly aimed at the electric field component whose effects can manifest themselves as the previously noted radio noise, audible noise, and nuisance shocks. The present focus is on the magnetic field because only it can penetrate the soil, building, and other materials to potentially produce the types of health impacts at the root of the present concern. As one focuses on the strong magnetic fields from the more visible overhead transmission and other high-voltage power lines, staff considers it important for perspective to note that an individual in a home could be exposed for short periods to much stronger fields while using some common household appliances such as hair dryers, electric shavers, and electric tooth brushes (National Institute of Environmental Health Services and the U.S. Department of Energy, 1995). Scientists have not established which of these types of exposures would be more biologically meaningful in the individual. Staff notes such exposure differences only to show that high-level magnetic field exposures regularly occur in areas other than around high-voltage power lines.

SETTING

The proposed BEP II would be located on a 76-acre parcel within the expanded site of BEP I, approximately five miles west of the center of the city of Blythe, in Riverside County, California. The project's generators would be located approximately 600 feet south and 800 feet west of those of BEP I. The area around the project site and the BEP I lines to be used is either open space or used for citrus cultivation. There are no nearby residences or occupied buildings, meaning that the long-term residential field exposures of the present concern would be insignificant with respect to these lines. The width of each line right-of-way is 100 feet. The new interconnection from the generators to the Buck Boulevard Substation would be a 2500 feet long 500 kV line, located entirely within the BEP site boundaries (Blythe Energy, 2002, pp. 7.2-3, 7.6-1).

Since there are no residences around the proposed project site or transmission lines to be utilized, the only project-related EMF exposures of potential significance to staff are the exposures to plant workers, regulatory inspectors, maintenance personnel, approved guests, or individuals in transit across the project's lines. These types of exposures are short-term and well understood as not significantly related to the present EMF-related health concerns.

PROJECT DESCRIPTION

The proposed BEP II and related facilities would consist of the following major segments:

- a new 500 kV line extending 2500 feet from BEP II's on-site integration switchyard to connect the project's generators with Western's Buck Boulevard 116/500 kV Substation;
- the permitted BEP I-related lines through which the generated power would be transmitted into the area's 161 kV grid lines via Western's Buck Boulevard and Blythe Substation;
- an on-site integration switchyard; and
- project-related modifications within the Buck Boulevard Substation.

As is typical for single-circuit 500 kV lines, the new on-site connection lines would be supported on steel lattice structures designed to provide a minimum conductor height of 65 feet, in keeping with GO-95 requirements. Construction and operation would be according to Western's standards and practices reflecting compliance with existing LORS. The Blythe Substation to be connected to the Buck Boulevard Substation presently interconnects with five 161 kV regional lines, three of which are owned by Western, one by the Imperial Irrigation District (IID), and the other by Southern

California Edison (SCE). The field impacts from the added BEP II power would mostly be encountered along the routes of these lines.

IMPACTS

GENERAL IMPACTS

GO-95 and Title 8, California Code of Regulations, section 2700 et seq., as noted in the LORS section, ensure the minimum regulatory requirements necessary to prevent the direct or indirect contact hazard previously discussed in connection with hazardous shocks or aviation hazards. The noted field impacts that manifest themselves as nuisance shocks, radio noise, communications interference, and magnetic field exposure are of secondary concern. The relative magnitude of such impacts would be reflected in the field strengths characteristic of a given line design. Given the present CPUC requirement to maintain the noted impacts within the levels associated with existing lines, compliance with applicable LORS would be achieved by showing the project-specific fields (from the new on-site lines or existing BEP lines to be utilized) to be within the range associated with Western's lines of the same voltage and current-carrying capacity.

PROJECT SPECIFIC IMPACTS

Aviation Safety

As noted by the applicant, (Blythe Energy 2002, page 7.17-8), the Blythe Airport is located approximately one mile from the project site, pointing to the potential of a collision hazard to utilizing aircraft. Since the existing BEP I lines to be utilized are owned and operated by Western, they were designed and sited in compliance with FAA regulations regarding aviation safety. As noted by the applicant (Blythe Energy 7.17-8) the BEP II site is 60 feet to 70 feet lower in elevation than the Blythe Airport. When this is considered together with the fact that the proposed on-site interconnecting 500 kV lines would be less than the 200-foot FAA height threshold for a potentially significant collision hazard, the line could be seen as unlikely to constitute a new collision hazard to area aircraft. As is common industry practice, however, the applicant will inform the FAA about the proposed project lines, although no FAA notification would be required.

Audible Noise and Interference with Radio-Frequency Communication

The previously noted corona-related communications interference is most commonly caused by irregularities (such as nicks and scrapes on the conductor surface), sharp edges on suspension hardware, and other discontinuities around the conductor surface. All existing Western lines were built and are currently maintained according to standard Western practices that minimize such surface irregularities and discontinuities. The low-corona design to be used for the new on-site line would be the same as used for other Western lines of the same voltage (Blythe Energy 2002, page 7.17-5) in compliance with the previously noted FCC (47 CFR §15.25) and GO-52 prohibitions against interference with radio communication. Since (a) the edge of the right-of-way would mark the beginning of the areas of possible human habitation around a high-voltage line, and (b) there are no residences around any of the project-related lines, staff does not expect BEP II operations to generate any complaints about operational noise, or interference with the use of residential radio, television, or other electrical equipment. In the unlikely event of specific complaints, Western would be responsible (as with other Western lines) for the necessary mitigation as required by the FCC. Staff recommends a specific condition of certification (**TLSN-2**) in this regard. For an assessment of noise from all aspects of the project construction and operation, please see staff's analysis in the **Noise and Vibration** section.

Fire Hazards

Standard fire prevention and suppression measures for all of Western's lines would be implemented for the proposed BEP II on-site 500 kV lines and would be maintained as is standard Western practice for the BEP lines to be utilized. The applicant's intention to ensure compliance with the clearance-related aspects of GO-95 would be an important part of this compliance approach (Blythe Energy 2002, page 7.17-9). Western's fire prevention practices for high-voltage lines would be implemented in compliance with Title 14, California Code of Regulations, section 1250. Staff recommends Condition of Certification **TLSN-4** to ensure implementation.

Hazardous Shocks

Since the existing BEP I lines to be utilized are Western lines, they were designed (as would the proposed on-site 500 kV line) according to GO-95 requirements together with the requirements in specific sections of Title 8, California Code of Regulations, section 2700 et seq. against direct contact with the energized line. Staff does not expect their use to pose a significant shock hazard.

Nuisance Shocks

The potential for nuisance shocks around the new on-site project line would be minimized through standard grounding practices, as are the permitted BEP I and similar Western lines. Staff recommends Condition of Certification **TLSN-5** to ensure that such practices are extended to the proposed on-site line.

Electric and Magnetic Field Exposure

The applicant assessed the potential contribution of the proposed BEP II to the maximally impacted grid lines located along the Buck Boulevard to Blythe Station corridor by comparing the fields from BEP I power flow alone, to fields from the combined flow of power from BEP I and BEP II (Blythe Energy 2002, pp. 7.17-3 through 7.17-5, 7.17-6 through 7.17-8). Staff is in agreement with the applicant's assumptions with respect to parameters bearing on field strength dispersion and exposure levels. Calculations were specifically made for the edges of the line rights-of-way, near the Buck Boulevard and Blythe Substations, and the points of maximum intensities within the rights-of-way. According to the applicant's calculations, the maximum strength of the background BEP-I related electric fields within this corridor of maximum impacts is 1.8 kV/m, diminishing to 0.5 kV/m at the edge of the right-of-way. The maximum around the substations was calculated as 1.4 kV/m.

The magnetic field strengths to be encountered within the BEP lines' rights-of-way before introduction of BEP II-related power was calculated as 68.9 mG at the point of maximum impact within the rights-of-way and as 9.7 mG at the edges of the rights-of-way. The maximum value around the Buck Boulevard and Blythe Substations was calculated as 78.2 mG.

The utilized lines would be operated at the existing 161 kV; therefore, the resulting corridor electric fields should remain the same during BEP II operations. This relative lack of change is reflected by the applicant's calculated values of 1.8 kV/m within the right-of-way and 0.5 kV/m at the edge of the right-of-way. The maximum field intensity around the substations was calculated as 1.4 kV/m. These electric field values are within the values staff would expect for Western lines of the same design and are within the limits of between 1.0 kV/m and 2.0 kV/m specified for the edges of rights-of-way in states with regulatory limits.

Since the magnetic field is the only line field that directly depends on current level, the increased power from BEP II would increase the corridor magnetic field strengths in proportion to the related increase in transmitted power. The applicant calculated the maximum magnetic field strength within the rights-of-way during BEP II power flow as 60.4 mG, diminishing to 8.5 mG at the edge of these rights-of-way. The maximum intensity around the two substations was calculated as 74.4 mG. Staff considers these field strength decreases as reflecting the power to be diverted to the 118-mile 500 kV line to be built by the Imperial Irrigation District to transmit the generated power from the Buck Boulevard Substation to the Devers Substation to the south.

The calculated corridor magnetic fields are within the range staff would expect for Western lines of the same current-carrying capacity and much lower than the 150 mG to 250 mG specified for the edges of the rights-of-way by the few states with specific regulatory limits.

These calculated field strengths reflect the effectiveness of Western's standard field reduction measures as applied with respect to the following:

- distance between the conductors and the ground;
- spacing between conductors on the same line;
- distance between conductors in nearby lines;
- line current levels; and
- current flow alignment for effective field cancellation.

These field reduction measures would be applied to the proposed on-site 500 kV connecting lines, in keeping with Western's practices ensuring compliance with current CPUC policy on field strength management. Staff recommends Condition of Certification **TLSN-3** to allow for validation of the reduction efficiency attributable to the design in question.

CUMULATIVE IMPACTS

The previously noted magnetic fields were calculated to reflect the interactive effects of the fields from all the grid lines in the corridor of maximum BEP II impacts and should therefore be seen as representing the maximum post-BEP II exposures of a cumulative nature. As reflected in the calculated values, the lines' potential contribution to any area exposures would be similar to those associated with area Western lines of the same voltage and current-carrying capacity. It is this similarity in field intensity (which reflects the effective implementation of the applicable field strength-minimizing measures) that constitutes compliance with existing CPUC requirements on line field management. The field strength measurement requirements in Condition of Certification **TLSN-3** would allow for assessment of the field strength reduction efficiency assumed by the applicant. The power diversion through the proposed 118-mile line to the Devers Substation would decrease cumulative magnetic field exposure by the amounts reflected in the pre- and post-BEP II field strengths.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population as greater than 50 percent in some areas within a six-mile radius of the proposed BEP II site (please refer to **Socioeconomics Figure 1** in this staff assessment). Census 2000 information suggests the population of the low-income individuals in the area as presently less than 50 percent, meaning that there would be no issue of environmental justice (on the basis of income) for the field impacts of concern in this analysis. The above noted minority profile caused staff to conduct a screening level analysis for potential environmental justice issues on the basis of minority status. Since, (a) there are no residences around the project site and the transmission lines to be utilized, and (b) the existing and proposed field reduction designs are standard Western designs that are applied throughout the Western service area without regard to minority status, staff regards the field exposure aspect of the environmental justice issue as insignificant for the proposed lines.

COMPLIANCE WITH LORS

The magnitude of the line impacts of concern in this analysis are within the limits associated with similar transmission lines designed and operated in compliance with Western's field strength reduction guidelines that reflect compliance with present CPUC requirements. Staff, therefore, considers the proposed on-site project transmission line design and operational plan to be in compliance with the health, safety, and design LORS of concern in this analysis. The fields from the BEP lines to be utilized reflect appropriate incorporation of Western field reduction measures in compliance with CPUC policy.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No public agency or public comments have been received in connection with the project-related impacts discussed in this analysis.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Since electric or magnetic field health effects have neither been established nor ruled out for overhead or underground lines, the public health significance of any BEP I or BEP II-related field exposures cannot be characterized with certainty. The long-term, mostly residential magnetic exposure at the root of the present health concern would be insignificant during operations. On-site worker or public exposures would be short-term and at levels associated with Western lines of the proposed voltage and current-carrying capacity. Such exposures are well understood and have not been established as posing a health hazard to humans.

The potential for nuisance shocks would be minimized through grounding and other field-reducing measures applied to all Western lines. As with the existing BEP lines to be utilized, the support structures for the proposed connecting on-site lines are not tall enough above ground to pose a significant collision hazard to utilizing aircraft. The use of corona-minimizing design and construction practices for both the BEP lines to be utilized and the proposed connecting on-site 500 kV line would minimize the potential for corona noise and its related interference with radio-frequency communication around the site.

RECOMMENDATIONS

As with the BEP lines to be utilized, the proposed 500 kV on-site project lines would be designed and operated to minimize the safety and nuisance impacts of specific concern to staff (while also located away from area residences). Staff does not recommend any changes to the proposed power transmission plan. If the proposed power plant is approved, staff recommends adoption of the conditions of certification specified below to ensure (a) implementation of the reduction measures proposed for the new on-site lines and (b) validation of the exposure levels assumed from use of the permitted BEP lines.

CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall ensure that the proposed on-site 500 kV project line is designed and constructed according to the requirements of CPUC's GO-95, GO-52, the applicable sections of Title 8, California Code of Regulations section 2700 et seq., and Western's EMF reduction guidelines arising from CPUC Decision 93-11-013.

<u>Verification:</u> Thirty days before starting construction of the BEP II transmission lines or related structures and facilities, the project owner shall submit to the Compliance Project Manager (CPM) a letter signed by a California registered electrical engineer affirming compliance with this requirement.

TLSN-2 The project owner shall ensure that every reasonable effort will be made to identify and correct, on a case-specific basis, any complaints of interference with radio or television signals from operation of the project-related lines and associated switchyards.

The project owner shall maintain written records, for a period of five years, of all complaints of radio or television interference attributable to operation of the plant and the corrective action taken in response to each complaint. Complaints not leading to a specific action or for which there was no resolution should be noted and explained. The record shall be signed by the project owner and also the complainant, if possible, to indicate concurrence with the corrective action or agreement, with the justification for a lack of action.

Verification: All reports of line-related complaints shall be summarized for the project-related lines and included for the first five years' of plant operation in the Annual Compliance Report.

TLSN-3 The project owner shall engage a qualified consultant to measure the strengths of the electric and magnetic fields from the proposed on-site 500 kV lines and the BEP I lines to be utilized. For the new 500 kV line, the measurements shall be made at the related switchyard and the points of maximum field intensity along the on-site route. The fields from the BEP II line to be utilized shall be measured at the Substations and the locations along the route for which the applicant presented field strength estimates. All measurements should be made according to Institute of Electrical and Electronics Engineers (IEEE) measurement protocols.

Verification: The project owner shall file copies of the pre-and post-energization measurements with the CPM within 30 days after completion of the measurements, which shall be initiated within 60 days from the beginning of operations.

TLSN-4 The project owner shall ensure that the route of the project's on-site 500 kV line is kept free of combustible material according to existing Western practices reflecting compliance with the provisions of Section 4292 of the Public Resources Code and Section 1250, Title 14, of the California Code of Regulations.

Verification: At least 30 days before the line is energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.

TLSN-5 The project owner shall ensure that all permanent metallic objects within the right-of-way of the proposed 500 kV on-site lines are grounded according to industry standards.

Verification: At least 30 days before the line is energized, the project owner shall transmit to the CPM a letter confirming the intention to comply with this condition. A confirmatory letter of compliance shall be transmitted to the CPM within 30 days of completing the grounding operations.

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VISUAL RESOURCES

Dale Edwards

SUMMARY

Energy Commission staff analyzed both the potential visual impacts of the proposed Blythe II Energy Project (BEP II) and the compliance of the project with applicable laws, ordinances, regulations, and standards (LORS). Staff's conclusions are as follows:

- As presently proposed, the project's structures would result in adverse but less than significant visual impacts. Staff has proposed conditions of certification (**VIS-2** and **VIS-3**) to more fully develop and implement the applicant's proposed mitigation measures and reduce structure impacts to levels that would not be significant.
- The proposed project's night lighting has the potential to cause significant visual impacts on passing motorists on nearby roadways and one residence. Staff's Conditions of Certification **VIS-4** and **VIS-5** would reduce lighting impacts to levels that would not be significant.
- As presently proposed, the project's contributions to cumulative visual impacts and cumulative lighting impacts would not be cumulatively considerable. Staff has proposed conditions of certification (**VIS-2**, **VIS-3**, **VIS-4** and **VIS-5**) to minimize the project's adverse contribution to the cumulative impact.
- As presently proposed, the project would be consistent with local LORS.

INTRODUCTION

Visual resources are the natural and cultural features of the environment that can be viewed. This analysis focuses on whether BEP II would cause significant adverse visual impacts and whether the project would be in compliance with applicable laws, ordinances, regulations, and standards. The determination of the potential for significant impacts to visual resources resulting from the proposed project is required by the California Environmental Quality Act (CEQA).

ORGANIZATION OF ANALYSIS

This analysis is organized as follows:

- Description of analysis methodology;
- Description of applicable laws, ordinances, regulations and standards;
- Description of the project aspects that may have the potential for significant visual impacts;
- Assessment of the visual setting of the proposed power plant site and linear facility routes;
- Evaluation of the visual impacts of the proposed project on the existing setting;
- Evaluation of compliance of the project with applicable laws, ordinances, regulations, and standards;

- ∉ Identification of measures needed to mitigate any potential significant adverse impacts of the proposed project and to achieve compliance with applicable laws, ordinances, regulations, and standards;
- ∉ Conclusions and Recommendations; and
- ∉ Proposed Conditions of Certification.

ANALYSIS METHODOLOGY

Visual resources analysis has an inherently subjective aspect. However, the use of generally accepted criteria for determining impact significance and a clearly described analytical approach aid in developing an analysis that can be readily understood.

Significance Criteria

Commission staff considered the following criteria in determining whether a visual impact would be significant.

State

The CEQA Guidelines define a "significant effect" on the environment to mean a "substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project including...objects of historic or aesthetic significance" (Cal. Code Regs., tit.14, § 15382).

Appendix G of the Guidelines, under Aesthetics, lists the following four questions to be addressed regarding whether the potential impacts of a project are significant:

1. Would the project have a substantial adverse effect on a scenic vista?
2. Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?
3. Would the project substantially degrade the existing visual character or quality of the site and its surroundings?
4. Would the project create a new source of substantial light or glare that would adversely affect day or nighttime views in the area?

Local

Energy Commission staff considers any local goals, policies, or designations regarding visual resources. Conflicts with such laws, ordinances, regulations, and standards can constitute significant visual impacts. See the section on Laws, Ordinances, Regulations, and Standards.

Professional Standards

Professionals in visual impact analysis have developed a number of questions as a means of evaluating the potential significance of visual impacts (see Smardon et al. 1986). The questions listed below address issues commonly raised in visual analyses for energy facilities. Staff considers these questions in assessing whether a project would cause a significant impact in regard to any of the four CEQA criteria listed above.

- Will the project substantially alter the existing viewshed, including any changes in natural terrain?
- Will the project deviate substantially from the form, line, color, and texture of existing elements of the viewshed that contribute to visual quality?
- Will the project eliminate or block views of valuable visual resources?
- Will the project result in significant amounts of backscatter light into the nighttime sky?
- Will the project be in conflict with directly identified public preferences regarding visual resources?
- Will the project result in a significant reduction of sunlight, or the introduction of shadows, in areas used extensively by the community?
- Will the project result in a substantial and persistent visible exhaust plume?

Impact Duration

The visual analysis typically distinguishes three different impact durations. **Temporary impacts** typically last no longer than two years. **Short-term impacts** generally last no longer than five years. **Long-term impacts** are impacts with duration greater than five years.

View Areas and Key Observation Points

The proposed project would be visible from a number of areas in the project region. Energy Commission staff evaluated the visual impact of the project from each of these areas. Staff used Key Observation Points[1], or KOPs, as representative locations from which to conduct detailed analyses of the proposed project and to obtain existing conditions photographs and prepare visual simulations. KOPs are selected to be representative of the most critical locations from which the project would be seen. However, KOPs are not the only locations that staff considered in each view area.

Evaluation Process

For each view area, staff considered the existing visual setting and the visual changes that the project would cause to determine impact significance. Staff conducted a site visit and concluded that the KOPs presented in the application were insufficient for this analysis given the change in the project location since the original AFC was submitted. Staff added KOP 7 on westbound Interstate 10 (I-10).

The results of staff's analysis are summarized in **Visual Resources Appendix VR-1**. Existing conditions photographs and photosimulations from each KOP are presented with all other figures in **Visual Resources Appendix VR-3** (with the exception that a simulation has not been prepared for KOP 7).

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[1] The use of KOPs or similar view locations is common in visual resource analysis. The U.S. Bureau of Land Management (USDI BLM 1986a, 1986b, 1984) and the U.S. Forest Service (USDA Forest Service 1995) use such an approach.

Elements of the Visual Setting

To assess the existing visual setting, staff considered the following elements:

Visual Quality

Visual quality is an expression of the visual impression or appeal of a given landscape and the associated public value attributed to the visual resource. This analysis used an approach that considers visual quality as ranging from outstanding to low. Outstanding visual quality is a rating reserved for landscapes that would be what a viewer might think of as "picture postcard" landscapes. Low visual quality describes landscapes that are often dominated by visually discordant human alterations, and do not provide views that people would find inviting or interesting (Buhyoff et al. 1994).

Viewer Concern

Viewer concern is a measurement of the level of viewer interest regarding the visual resources in an area. Official statements of public values and goals reflect viewers' expectations regarding a visual setting. This analysis also employed land use as an indicator of viewer concern. Uses associated with 1) designated parks, monuments, and wilderness areas, 2) scenic highways and corridors, 3) recreational areas, and 4) residential areas are generally considered to have high viewer concern. However, existing landscape character may temper viewer concern on some State and locally designated scenic highways and corridors. Similarly, travelers on other highways and roads, including those in rural or agricultural areas, may have moderate viewer concern depending on viewer expectations as conditioned by regional and local landscape features. Commercial uses and their occupants, including business parks and hotels, typically have low-to-moderate viewer concern, though some commercial developments have specific requirements related to visual quality, with respect to landscaping, building height limitations, building design, and prohibition of above-ground utility lines, that indicate high viewer concern. Industrial uses typically have the lowest viewer concern because workers are focused on their work, and generally are working in surroundings with relatively low visual value.

Viewer Exposure

The visibility of a landscape feature, the number of viewers, and the duration of the view all affect the exposure of viewers to a given landscape feature. Visibility is highly dependent on screening and angle of view. The smaller the degree of screening and/or the closer the feature is to the center of the view area, the greater its visibility is. Increasing distance reduces visibility. Viewer exposure can range from low values for all factors, such as a partially obscured and brief background view for a few motorists, to high values for all factors, such as an unobstructed foreground view from a large number of residences.

Visual Sensitivity

The overall level of sensitivity of a view area to impacts due to visual change is a function of visual quality, viewer concern, and viewer exposure and can range from low to high.

Types of Visual Change

To assess the visual changes that the project would cause, staff considered the following factors:

Contrast

Visual contrast describes the degree to which a project's visual characteristics or elements (consisting of form, line, color, and texture) differ from the same visual elements established in the existing landscape. The degree of contrast can range from low to high. The presence of forms, lines, colors, and textures in the landscape similar to those of a proposed project indicates a landscape more capable of accepting those project characteristics than a landscape where those elements are absent. This ability to accept alteration is often referred to as visual absorption capability and typically is inversely proportional to visual contrast.

Dominance

Another measure of visual change is project dominance. Dominance is a measure of a feature's apparent size relative to other visible landscape features and the total field of view. A feature's dominance is affected by its relative location in the field of view and the distance between the viewer and the feature. The level of dominance can range from subordinate to dominant.

View Blockage

View blockage describes the extent to which any previously visible landscape features are blocked from view by the project. Blockage of higher quality landscape features by lower quality project features causes adverse visual impacts. The degree of view blockage can range from none to high.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The proposed project would be subject to the laws, ordinances, regulations, and standards (LORS) of Riverside County and the City of Blythe. Program 2 of Riverside County's Comprehensive General Plan would apply to the proposed project and is evaluated later in this Staff Assessment.

CITY OF BLYTHE ZONING ORDINANCE

Requires a site development plan that complies with the applicable design criteria and performance standards for the General Industrial District.

PROJECT DESCRIPTION

The following section describes the aspects of the project that may have the potential for significant visual impacts, including the power generation and associated facilities, switchyard, and electric transmission interconnection (see **VISUAL RESOURCES Figures 1** through **3** in **Appendix VR-3**).

POWER PLANT AND ASSOCIATED FACILITIES

The proposed generating facility would be located within the city limits of Blythe, adjacent and to the southwest of the existing Blythe Energy Project (BEP I) facilities and within the 152-acre site boundary of BEP that is bordered on the east by Buck Boulevard and on the south by Hobsonway. The site is approximately five miles west of the center of Blythe. The BEP II power island would be located approximately 1,300 feet southwest of the BEP I power island. **VISUAL RESOURCES Table 1** presents the dimensions for a number of the project's key components. The most visible features of the proposed power generation facilities would include the two 130-foot tall heat recovery steam generator (HRSG) stacks; the 98-foot tall brine concentrator, the 93-foot tall HRSGs, the 60-foot tall by 75-foot long by 330-foot wide generation building, and the 40-foot tall by 52-foot wide by 472-foot long cooling tower.

VISUAL RESOURCES Table 1
Dimensions of Key Project Components

Component	Height (feet)	Length (feet)	Width (feet)	Diameter (feet)
HRSG Units				
HRSG Casings	93	140	60	
HRSG Stacks	130			18
Generation Building				
Generation Building	60	75	330	
Cooling Tower				
Cooling Tower	40	472	52	
Tanks				
Raw Water Supply Tank	43			80
Demineralized Water Storage Tank	43			40
Other Facilities and Buildings				
Brine Concentrator	98			17
Control Room Building	15	115	40	
Power Control Center	16	25	20	
Workshop/Storage	31	50	120	
Fire Pump House	19	42	27	
Ammonia Storage Area	13	45	30	
Feedwater Pumphouse	26	67	37	
CEM Enclosure	8	24	7	

Source: BEP II 2002a, Table 7.5-1

SWITCHYARD

The generation facilities of BEP II would be connected directly to the Western Area Power Administration (Western) Buck Boulevard Substation, located at the northeastern corner of the BEP site. As a result, BEP II would not require a separate switchyard though it would require the addition of breaker positions within the Buck Boulevard Substation.

WATER EVAPORATION PONDS

BEP II would require an additional 6.48-acre water evaporation pond that would be south of the BEP II power island, adjacent to Hobsonway. The pond would be surrounded by an approximately 5-foot tall earthen berm.

CONSTRUCTION LAYDOWN AREAS

During project construction, a 12.4-acre area, central to the overall 152-acre BEP site would be used for construction laydown and parking (see **Visual Resources Figure 1**).

ACCESS ROADS

Access to the project site would be available from Hobsonway to the south and Buck Boulevard to the east.

LINEAR FACILITIES

BEP II would require no off-site linear facilities and would interconnect on-site with existing BEP approved transmission and natural gas pipelines (BEP II 2002a, AFC p. 7.5-1).

WATER CONSERVATION OFFSET PLAN

The Applicant has proposed a voluntary Water Conservation Offset Plan (WCOP) to offset the project's use of Colorado River water pumped as groundwater. The plan would call for BEP II to fallow land that has been under agricultural use within the last five years to offset the project's annual use of approximately 3,300 acre-feet of Colorado River water pumped as groundwater from wells at the plant site. The information provided by the applicant indicates that a value of 4.2 acre-feet of water per acre of land fallowed would be used to calculate the number of acres that would need to be fallowed to offset the project's water use.

SETTING

REGIONAL LANDSCAPE

BEP II would be located on Palo Verde Mesa in eastern Riverside County. The project region encompasses broad, flat desert valleys and north-south trending, highly eroded mountain ranges that rise sharply from the adjacent basins. The region marks the transition zone between the high elevation Mojave Desert and the arid, lower elevation Colorado Desert. Typical landforms include mesas, valleys, mountains, and foothills. The elevation ranges from approximately 250 to 800 feet (BEP II 2002a, p. 7.5-2).

Most development within the region occurs within Palo Verde Valley along the west side of the Colorado River and includes the City of Blythe, the towns of Palo Verde and Ripley, as well as agricultural fields, railroad lines, power transmission lines, and the Palo Verde Dam and diversion works. Most of the agricultural activity in the region also occurs in the valley and is dominated by irrigated farming consisting primarily of row crops and alfalfa (BEP II 2002a, p. 7.5-2).

Overlooking Palo Verde Valley to the west lies the two-tiered Palo Verde Mesa. The mesa is a broad alluvial plain situated between, and derived from, the McCoy Mountains to the west, Little Maria Mountains to the north, and Big Maria Mountains to the northeast. To the south are the Mule and Little Chuckwalla Mountains. The mountain ranges add visual variety to the otherwise flat desert landscape.

PROJECT VIEWSHED

The distance zones used within this analysis are defined as *foreground* (0 to .5 mile), *middleground* (0.5 to two miles), and *background* (beyond two miles). These zones of influence contain a number of viewing opportunities. Because the site is situated on an elevated mesa, from lower elevations to the east including the City of Blythe, ground level components would generally be only visible from foreground viewing opportunities in close proximity of the site, typically on Hobsonway and I-10. However, the taller portions of the plant facilities would be visible at distances greater than 10 miles because of the relatively flat terrain and minimal view obstructions. The majority of viewers of the site would be motorists on I-10, located approximately 0.25 mile south of the site; commercial areas on the east side of Blythe Airport to the west; rural residences; and the Blythe Municipal Golf Course and adjacent residences in the Mesa Bluffs area to the northeast. Other locations from which viewers would be able to see the project include the City of Blythe (located approximately five miles to the east), residential subdivisions on the mesa and in the valley, and recreational use areas in the surrounding mountains.

The Blythe Airport is considered potentially eligible for listing in the National Register of Historic Places and could be considered a sensitive viewing location. However, the plant site is located approximately 1.3 miles distant to the east and at an elevation approximately 58 to 60 feet lower than the airport. Thus, views of the plant site from the airport would be limited. Visibility would be attenuated with increasing distance, particularly at times of the year when dust and poor visibility conditions persist.

IMMEDIATE POWER PLANT VICINITY

BEP II would be located on the eastern lower tier of Palo Verde Mesa, which is characterized by a mostly undeveloped desert landscape of level terrain and sparse desert scrub vegetation interspersed with a small amount of irrigated agriculture and containing some industrial, utility, and transportation facilities. The most prominent built feature on the mesa is the recently constructed Blythe Energy Project (BEP I) with its prominent geometric forms and industrial character. Views of the mesa are panoramic in scope and encompass a landscape of generally uniform tan coloration interspersed with contrasting dark and light zones. Middleground views reveal a natural setting of stippled appearance due to the contrasts between vegetation, soil, and rock. Closer foreground views present a mosaic of sparse shrubby vegetation and desert pavement openings.

The project site and the surrounding landscape are characterized by views that are expansive, though views to the north are partially obstructed by the existing BEP I facilities. Beyond the immediate power plant and electric transmission infrastructure, structures are few and widely dispersed. Although the site is undeveloped, portions have been disturbed as a result of construction of BEP I, and several electric transmission lines cross the site and are supported on wood pole H-frame structures. To the east of the site are a citrus orchard and the Blythe Substation. Sewage disposal ponds are located adjacent to the site and to the southwest but are not generally visible from either Hobsonway or I-10. There are three rural residences located within one mile of the plant site and 32 residences located between one mile and two miles of the site. There are 112 residences between two to four miles from the site. There are an additional 77 residences between four and five miles of the site (BEP II 2002a, p. 7.5-11). Of these residences, there are 31 residences that would have views of the plant (BEP II 2002a, p. 7.5-19).

SWITCHYARD, ELECTRICAL TRANSMISSION INTERCONNECTION, AND LINEAR FACILITIES

The BEP II would interconnect on-site with the existing (BEP I) support infrastructure (electric, gas, water, brine return) and, therefore, would be within the immediate power plant vicinity, described above. Furthermore, the Desert Southwest Transmission Line Project Hobsonway Substation and 230 or 500 kV transmission line connecting to it would be located immediately adjacent to BEP II and are discussed in the Cumulative Impacts section later in this analysis.

WATER EVAPORATION POND

The proposed 6.52-acre water evaporation pond is within the power plant vicinity, described above.

CONSTRUCTION LAYDOWN AREA

The proposed construction laydown area would be located within the immediate power plant vicinity, described above.

WATER CONSERVATION OFFSET PLAN

The proposed WCOP would affect lands located within the immediate power plant vicinity and regional landscape described above.

VIEWING AREAS AND KEY OBSERVATION POINTS

Staff evaluated the visual setting and proposed project in detail from several viewing areas represented by the following seven key observation points including:

- KOP 1 – Eastbound Interstate 10, approximately 0.3 mile southwest of the project site;
- KOP 2 – Eastbound Hobsonway, approximately 0.4 mile west of the project site;
- KOP 3 – Mesa Verde (Nicholls Warm Springs), approximately 2.5 miles southwest of the project site off Mesa Drive and just south of Interstate 10;
- KOP 4 – Central Blythe, approximately 4 miles east of the project site at Hobsonway and the “C” Canal Levee;
- KOP 5 – Blythe Municipal Golf Course, approximately 4.5 miles northeast of the project site;

- KOP 6 – Westbound Hobsonway at Buck Boulevard, at the southeast corner of the project site; and
- KOP 7 – Westbound Interstate 10, southeast of the BEP site.

Each of these key observation points is shown on **Visual Resources Figure 4**. At each KOP a visual analysis was conducted, the results of which are presented in **Appendix VR-1**. Existing condition photographs are presented in **Appendix VR-3**. A discussion of the visual setting for each KOP is presented in the following paragraphs.

KOP 1 – Eastbound Interstate 10

KOP 1 was selected to characterize the visual impact to eastbound motorists on I-10. KOP 1 is located on eastbound I-10, approximately 0.3 mile southwest of the project site and immediately east of the upper mesa eastern face. The view is to the northeast and is depicted in Visual Resources Figure 5A. This location provides an open and unobstructed view of the site. The foreground to middleground terrain is flat and supports a sparse desert scrub vegetation. The existing Blythe Energy Project (BEP I) is the dominant feature in the landscape. The project would be visible in the foreground along with a number of existing transmission line structures, the Blythe Substation, adjacent citrus orchard, and BEP I, which is the dominant feature in the landscape. To the east, the Dome Rock Mountains are visible as distant background elements.

Visual Quality

Just after descending the upper tier of the mesa, the view to the east and northeast from I-10 encompasses middleground to background panoramic scenes of a broad, level, desert mesa landscape lacking distinctive features and containing energy transmission infrastructure, roadside signage, and irrigated orchards. The dark green color of the orchard provides some color contrast with the surrounding tan desert soils and vegetation. The most prominent foreground to middleground landscape features are the swaths of dark pavement that comprise I-10. The distant Dome Rock Mountains provide a backdrop of angular landforms. The general lack of scenic features or elements of visual interest, combined with the presence of BEP I, numerous transmission line structures, utility poles, and Blythe Substation contribute to a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations at this location are conditioned by the vicinity landscape along I-10 which includes, unobstructed, panoramic landscapes, the presence of numerous electric transmission structures, Blythe Substation, and occasional geometric block forms such as the existing commercial establishment and facilities adjacent to the airport (which are not visible from KOP 1) and the new Blythe Energy Project (BEP I). The BEP I facility will gradually condition viewer expectations to the presence of a large industrial facility in the immediate site vicinity. Views also include the high traffic volumes and large trucks with containers of rectangular block form on I-10. Of the approximately 16,300 to 17,100 motorists per day on I-10, about 40 percent are heavy trucks (BEP II 2002a, p. 7.5-5). Overall viewer sensitivity is rated low-to-moderate.

Viewer Exposure

In spite of an indirect view, site visibility is high in that the view of the site from KOP 1 is from a slightly elevated perspective and is generally unobstructed at a foreground viewing distance. The number of viewers is high and the view duration for eastbound motorists on I-10 would be moderate. The high visibility and numbers of viewers and moderate duration of view would contribute to moderate-to-high viewer exposure.

Overall Visual Sensitivity

For viewers at KOP 1, the low-to-moderate visual quality and viewer concern, combined with a moderate-to-high viewer exposure result in an overall moderate visual sensitivity of the visual setting and viewing characteristics.

KOP 2 – Eastbound Hobsonway

KOP 2 was selected to characterize the visual impact to eastbound traffic on Hobsonway. KOP 2 is located on Hobsonway, near a residence that is located on the eastern face of the mesa's upper tier, approximately 0.4 mile west of the project site. The view is to the east-northeast and is depicted in **Visual Resources Figure 6A**. This location provides a slightly elevated view over the site that is open and unobstructed. The foreground to middleground terrain is flat and supports sparse desert scrub vegetation. The project would be visible within the primary cone of vision in the foreground along with a number of existing transmission line structures, the recently completed Blythe Energy Project, Blythe Substation, the paved lanes of Hobsonway, and the nearby citrus orchard. Other roadside utility poles are visible as they transition from the foreground to background away from the viewer along the north side of Hobsonway. To the east, the Dome Rock Mountains are visible as distant background elements.

Visual Quality

Views to the east-northeast from KOP 2 and the adjacent residence encompass foreground to background panoramic scenes of a broad, level, desert mesa landscape lacking distinctive features and containing prominent energy generation (BEP I) and transmission infrastructure and irrigated orchards. The most prominent landscape features are the recently constructed BEP I with its industrial character and the narrow, linear ribbon of gray pavement that comprises Hobsonway. Portions of the Palo Verde Valley are visible in the background and the distant Dome Rock Mountains provide a backdrop of angular landforms that add some visual variety and interest. The tan desert soils and dark greenish-brown desert scrub vegetation are the dominant coloration in a landscape generally lacking vivid coloration or color contrast. The limited visibility of scenic features and elements of visual interest combined with the presence of BEP I, numerous transmission line structures, utility poles, and Blythe Substation contribute to a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations at this location are conditioned by the vicinity landscape along Hobsonway, which includes a panoramic landscape of prominent energy generation and transmission infrastructure and occasional geometric block forms such as the existing commercial establishment and facilities adjacent to the airport (which are not visible from KOP 2). Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. However, any increase in industrial character would be seen as an adverse visual change. Viewer sensitivity is rated low-to-moderate for motorists on Hobsonway.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 2 is slightly elevated and generally unobstructed at a foreground viewing distance. While the number of viewers is low, the view duration for eastbound motorists on Hobsonway would be extended with a direct angle of view. The high visibility and extended duration of view would be somewhat moderated by the low numbers of viewers. Therefore, viewer exposure would be moderate-to-high for motorists on Hobsonway.

Overall Visual Sensitivity

For eastbound motorists at KOP 2, the low-to-moderate visual quality and viewer concern, combined with moderate-to-high viewer exposure, result in an overall moderate visual sensitivity.

KOP 3 – Mesa Verde (Nichols Warm Springs)

KOP 3 was selected to capture the potential visual impact to the nearest major residential area. The Mesa Verde (Nicholls Warm Springs) residential subdivision is located south of Blythe Municipal Airport, adjacent, and to the south of, I-10. KOP 3 was established on the north side of the subdivision at a distance of approximately 2.5 miles southwest of the project site. A number of residences along the north and east perimeter of the subdivision would have distant, indirect views of the proposed project. The viewshed to the northeast from KOP 3 includes the characteristic sparsely vegetated, tan-colored desert landscape in the foreground to middleground, a few structures on the north side of I-10 adjacent to the airport, and several transmission lines extending across the flat desert landscape and the recently completed BEP I. The Blythe Substation is barely discernible in the background (see **Visual Resources Figure 7A**).

Visual Quality

Views to the northeast from the north side of the Mesa Verde residential subdivision encompass foreground to background panoramic scenes of a broad, level, desert mesa landscape with a dominant monotone tan coloration and lacking distinctive features. I-10 features prominently in the foreground to middleground landscape. The viewshed is typical of the region and is punctuated by energy transmission infrastructure and facilities associated with Blythe Municipal Airport. Noticeable at a distance is the complex industrial appearance of the recently completed BEP I. Though barely visible above the horizon, the distant Big Maria and Dome Rock Mountains provide a faint backdrop of angular landforms of lavender coloration. The lack of vivid coloration and the limited visibility of scenic features and color contrast, or elements of visual interest, combined with the presence of energy and transportation infrastructure contribute to a low-to-moderate rating for visual quality.

Viewer Concern

Although residential uses are generally attributed a high degree of viewer concern, viewer concern is also conditioned by existing landscape characteristics and quality, visibility, and primary view direction. At the Mesa Verde Subdivision, most primary (front of residence) views along the north and east side of the subdivision (represented by KOP 3) are directed to the south and west away from the direction of the proposed project. Also, the project is located at a substantial distance from the subdivision, thus reducing project visibility. Furthermore, between the project and the subdivision is I-10 with a continuous flow of vehicles, many of which are large tractor-trailers with large containers of rectangular, geometric form. Also present in northern views from the subdivision are structures on the north side of I-10 in close proximity to Blythe Airport. Views in the direction of the proposed project encompass numerous built features including the recently completed BEP, thus, tempering viewer expectations and lowering viewer concern to a moderate level at KOP 3.

Viewer Exposure

Project visibility is low due to the substantial distance between KOP 3 and the proposed project and the partial screening that occurs from a continual stream of vehicles on I-10, which intervenes between the viewer and the project site. The low project visibility at this background viewing distance combined with the low-to-moderate number of viewers with potentially extended views results in an overall moderate viewer exposure at KOP 3.

Overall Visual Sensitivity

From the north side of the Mesa Verde residential development, the low-to-moderate visual quality combined with moderate viewer concern and moderate viewer exposure, lead to a moderate overall visual sensitivity of the visual setting and viewing characteristics.

KOP 4 – Central Blythe

KOP 4 is located adjacent, and to the north of, Hobsonway on the “C” Canal east levee adjacent to the K-Mart parking lot. This location is approximately four miles east of the project site and was selected to depict the closest view of the site from the City of Blythe urban center. The view from KOP 4 is panoramic, encompassing agricultural fields, the irrigation canal, Hobsonway, roadside utility infrastructure on wood poles that transition from the foreground to background, Palo Verde Mesa, and the McCoy Mountains in the distant background (see **Visual Resources Figure 8A**). The view to the site from KOP 4 would be direct though completely obscured by intervening vegetation.

Visual Quality

Views to the west from KOP 4 encompass foreground to middleground views of a landscape that has been substantially altered for agricultural, irrigation, transportation, and communication purposes. The viewshed is panoramic, providing scenes of broad, level agricultural fields and adjacent utility infrastructure, which is typical of the characteristic rural/cropland landscape common to the Palo Verde Valley. The distant McCoy Mountains provide a faint lavender backdrop of angular forms, adding some visual variety though they appear low on the horizon. The green color of the agricultural fields is the dominant, though transient, coloration, which changes with crop stage. However, the lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest as well as the prominence of Hobsonway and roadside utility poles, contribute to a low-to-moderate rating for visual quality.

Viewer Concern

KOP 4 is located on the western edge of the urban center of Blythe. Viewers at this location are generally accessing commercial facilities or are in transit to other short-range destinations that are typically not considered visually sensitive activities or uses. Viewer expectations at this locale include the transitional landscapes between urban and rural settings that include various forms of infrastructure as well as agricultural and commercial uses. Although there are several residences in the vicinity of KOP 4 (primarily along Hobsonway), the residences do not have unobstructed views of the site since they generally face north or south toward Hobsonway and not to the west. Overall viewer concern is low.

Viewer Exposure

Site visibility is low at a background viewing distance, which along with a brief-to-moderate duration of view, offsets the moderate-to-high number of viewers at this location, leading to moderate viewer exposure.

Overall Visual Sensitivity

The low-to-moderate visual quality and low degree of viewer concern, combined with a moderate degree of viewer exposure result in a low-to-moderate overall visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 4.

KOP 5 – Blythe Municipal Golf Course & Residences

KOP 5 was selected to characterize the impact to the Blythe Municipal Golf Course and the adjacent residences, all of which are located on Palo Verde Mesa and have a direct, though distant (at approximately 4.5 miles), line of sight to the proposed plant site. KOP 5 is located in a small parking area adjacent to the Golf Course and several residences at the edge of the mesa (see **Visual Resources Figure 9A**).

This location provides a panoramic view to the south and southwest, encompassing the Palo Verde Valley in the foreground and middleground and the project site in the background. The Mule and Little Chuckwalla Mountains provide a distant backdrop to the site. The foreground to middleground terrain is flat and supports sparse desert scrub vegetation and a few irrigated agricultural parcels. Also visible in the distance is the City of Blythe, the airport, the citrus orchard immediately east of the site, the Blythe Substation, the numerous electric transmission lines that cross the site, and the recently constructed BEP I. At this distance, BEP I, the substation, and transmission lines are barely discernible. The view to the site from several residences and several of the golf course fairways and greens would be direct and extended.

Visual Quality

The panoramic views to the south and southwest overlook the Palo Verde Valley and Palo Verde Mesa. These vista views also encompass the mountains that ring the area.

Though much of the foreground to middleground landscape is dominated by agricultural fields and monotone desert scrub vegetation, the elevated perspective available from this KOP provides visual access to a regional landscape that offers more distinctive features with greater visual variety and interest. The color contrast of the tan soils and vegetation with the vivid green of irrigated croplands and the lavender of distant mountain ranges add to a more visually interesting landscape. Also, barely discernible at this background distance is the recently completed BEP I. Visual quality from KOP 5 is rated moderate-to-high.

Viewer Concern

Residences in the Mesa Bluffs area are situated along the mesa edge to take advantage of the vistas overlooking the Palo Verde Valley and Mesa. Also, the recreational users of the Municipal Golf Course (approximately 36,000 rounds of golf are played annually – BEP II 2002a, p. 7.5-7) have expectations for panoramic views and a predominantly naturally appearing landscape. Therefore, the viewers in the Mesa Bluffs area are considered to be sensitive to landscape changes and viewer concern is rated moderate-to-high.

Viewer Exposure

Site visibility is low due to the substantial distance between the golf course/Mesa Bluffs area and the project site. Though the number of potential viewers at the golf course is moderate, the site would only be visible from a few of the fairways and greens and would generally not be noticeable given the distance and indirect angle of view. The adjacent residences would have more direct viewing opportunities but again, the distance would generally limit project visibility. However, the low project visibility would offset the extended duration of view available to residents and golfers alike. Therefore, viewer exposure is low-to-moderate.

Overall Visual Sensitivity

For viewers along Mesa Bluffs, the moderate-to-high visual quality and viewer concern combined with the moderate viewer exposure, lead to a moderate-to-high assessment for overall visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 5.

KOP 6 – Westbound Hobsonway

KOP 6 was selected as one of two locations to characterize the impact to motorists on Hobsonway. KOP 6 is located on westbound Hobsonway at the southeast corner of the project site and captures the view of the site available to westbound motorists (see **Visual Resources Figure 10A**).

This location provides a panoramic view to the north and west encompassing the project site in the foreground and the Little Maria and Big Maria Mountains as distant background elements. The foreground to middleground terrain is flat and dominated by the recently completed BEP I. The foreground landscape is also crossed by numerous electric transmission lines. Also visible (but out of the frame of the photograph) is the citrus orchard east of the site and Blythe Substation. Due to the close proximity of the site to Hobsonway, the site is located within the primary cone of vision of westbound travelers on Hobsonway.

Visual Quality

Views to the north and west from Hobsonway encompass foreground to middleground panoramic scenes of a highly modified desert mesa environment that is dominated by energy generation and transmission infrastructure. While the immediate foreground lacks scenic features or elements of visual interest, the angular landforms of the distant Little Maria and Big Maria Mountains add some visual variety and interest though they appear low on the horizon. Portions of these features are blocked from view by the industrial forms of the recently completed BEP I. The lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest, combined with the dominant presence of the BEP and numerous transmission line structures, and Blythe Substation result in a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations along this portion of Hobsonway are conditioned by the vicinity landscape and must now consider the prominent presence of the recently completed BEP I along with the numerous electric transmission line structures and Blythe Substation. Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. Overall viewer concern is rated low-to-moderate.

Viewer Exposure

As previously stated, the proposed site is located within the primary cone of vision of travelers on Hobsonway and visibility would be high at this foreground viewing distance. Although the number of viewers would be low, the duration of view would be moderate to high. The overall viewer exposure would be moderate.

Overall Visual Sensitivity

For westbound motorists on Hobsonway, the low-to-moderate visual quality and viewer concern, combined with moderate viewer exposure result in a low-to-moderate visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 6.

KOP 7 – Westbound Interstate 10

KOP 7 was selected as one of two locations to characterize the impact to motorists on I-10. KOP 7 is located on westbound I-10, approximately 0.4 mile southeast of the project site and captures the view of the site available to westbound motorists (see **Visual Resources Figure 11**).

This location provides a panoramic view to the northwest encompassing the project site in the foreground with the prominent, recently completed BEP I in the near middleground, and the Little Maria and Big Maria Mountains as distant background elements. The foreground landscape is also crossed by numerous electric transmission lines. Also visible (but out of the frame of the photograph) is the citrus orchard east of the site and Blythe Substation. The site is visible within the primary cone of vision of westbound travelers on I-10.

Visual Quality

Views to the northwest from I-10 encompass foreground to middleground panoramic desert mesa scenes with prominent energy generation and transmission infrastructure. While the immediate foreground lacks scenic features or elements of visual interest, the angular landforms of the distant Little Maria and Big Maria Mountains add some visual variety and interest though they appear low on the horizon. A small portion of the background mountains are blocked from view by the industrial forms of the recently completed BEP I. The lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest, combined with the dominant presence of the BEP I, numerous transmission line structures, and Blythe Substation result in a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations along this portion of I-10 are conditioned by the vicinity landscape and must now consider the prominent presence of the recently completed BEP I along with the numerous electric transmission line structures and Blythe Substation. Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. Overall viewer concern is rated low-to-moderate.

Viewer Exposure

As previously stated, the proposed site is located within the primary cone of vision of travelers on I-10 and visibility would be high at this foreground viewing distance. The number of viewers would be high and the duration of view would be moderate. The overall viewer exposure would be moderate-to-high.

Overall Visual Sensitivity

For westbound motorists on I-10, the low-to-moderate visual quality and viewer concern combined with moderate viewer exposure result in a moderate visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 7.

IMPACTS

CONSTRUCTION IMPACTS

Construction of the proposed power plant and water evaporation pond would cause temporary visual impacts due to the presence of equipment, materials, and workforce. These impacts would occur at the proposed power plant site, the water evaporation pond site, and construction laydown areas. All of these components are located within, or immediately adjacent to, the proposed development site. Construction would involve the use of cranes, heavy construction equipment, temporary storage and office facilities, and temporary laydown/staging areas. Construction would include site clearing and grading, construction of the actual facilities, and site cleanup and restoration. Traffic would also increase dramatically along Hobsonway during construction. Construction activities would be visible from Hobsonway, nearby residences, and I-10 which is the primary travel corridor in the region. Due to the relatively short-term nature of project construction (18 to 22 months), adverse but not significant visual impacts are anticipated.

However, this conclusion assumes that restoration of construction areas not occupied by new facilities is accomplished. Proper implementation of staff's proposed mitigation in Condition of Certification **VIS-1** would ensure that the visual impacts associated with project construction remain less than significant. It is also anticipated that construction activity will take place at night. In order to ensure that significant construction lighting impacts do not occur, staff recommends mitigation in Condition of Certification **VIS-4**, presented later in this analysis.

OPERATION IMPACTS

An analysis of operation impacts was conducted for the view areas represented by the key viewpoints selected for in-depth visual analysis. The results of the operation impact analysis are discussed below by KOP and presented in the Visual Analysis Summary table included as **Visual Resources Appendix VR-1**. The visual impacts of vapor plume formation and night lighting are discussed in separate sections of this analysis. For each KOP, an evaluation of visual contrast, project dominance, and view blockage is presented with a concluding assessment of the overall degree of visual change caused by the proposed project.

Power Plant Structures

The proposed project would result in the addition of sizable geometric structures with industrial character to an undeveloped parcel immediately adjacent and to the southwest of the recently completed BEP I. The most prominent project structures would be the two 130-foot tall HRSG stacks; the 98-foot tall water treatment brine concentrator; the 93-foot tall HRSG structures; the 60-foot tall, 75-foot wide, and 300-foot long gas turbine building; and 40-foot tall, 52-foot wide, and 472-foot long cooling tower. The below grade evaporation pond will encompass 6.52 acres and be surrounded by a five-foot high earthen berm.

KOP 1 – Eastbound Interstate 10

Visual Resources Figure 5B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 1 on eastbound I-10. The most obvious change to the landscape would be the addition of the complex geometric structures comprising the power plant facilities.

Visual Contrast

The proposed project would add prominent industrial features to the foreground landscape including the geometric forms and complex lines of the HRSG structures, stacks, and cooling tower. While these structural characteristics and neutral colors would be consistent with the forms, lines, and colors established by the existing BEP I facilities, the industrial characteristics of the proposed BEP II structures would be more noticeable compared to the existing facilities given the closer proximity of the proposed project to I-10. The resulting visual contrast would be low-to-moderate (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

As illustrated in **Visual Resources Figure 5B**, compared to the existing BEP I facilities, the proposed project would appear larger in scale (though not so large as to dominate BEP I) given the closer proximity of the proposed project to I-10. The proposed project would also appear comparable in prominence to the broad, horizontal forms of the foreground desert mesa and I-10, and the angular forms of the background mountains. The proposed power plant facilities would appear spatially prominent in the primary cone of vision, and the extension of the HRSG stacks and structures above the horizon line would contribute to the project's structural prominence. Overall project dominance would be co-dominant.

View Blockage

From the vicinity of KOP 1, the HRSG structures and stacks and cooling tower (lower quality landscape features) would block from view portions of the background mountains and sky (higher quality landscape features) as well as portions of the existing BEP I (similar quality feature - though only briefly from the specific eastbound I-10 location illustrated in Figure 5B). The resulting view blockage would be low-to-moderate.

Overall Visual Change

From KOP 1, the values for visual contrast, project dominance, and view blockage, when taken together, constitute a low-to-moderate level of overall visual change.

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the low-to-moderate visual change that would be perceived from KOP 1 would cause an adverse but not significant visual impact.

KOP 2 – Eastbound Hobsonway

Visual Resources Figure 6B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 2 on eastbound Hobsonway and an adjacent residence, approximately 0.4 mile west of the project site. The most obvious change to the landscape would be the visibility of the HRSG structures and stacks and the eight-cell cooling tower.

Visual Contrast

The proposed project would add a prominent industrial facility to the foreground landscape. While the neutral colors and complex geometric forms and lines of the HRSG structures, stacks, and cooling tower would be consistent with the forms, lines, and colors established by the existing BEP I facilities, they would contrast with the simple horizontal landforms of the mesa landscape. The resulting visual contrast would be moderate-to-high (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The proposed project would be spatially prominent in the primary cone of vision of eastbound travelers on Hobsonway and the nearby residence. The mass and scale of the proposed structures would appear substantially greater than the existing BEP I structures and the project would appear more prominent than the distant Big Maria and Dome Rock mountain ranges given the close proximity of BEP II to Hobsonway and KOP 2. The solid massing of the geometric block structures and the structure skylining would increase the prominence of the proposed project. As a result, the proposed project would appear dominant to the existing natural landforms and built features.

View Blockage

From KOP 1, the HRSG structures and stacks and cooling tower (lower quality landscape features) would block from view noticeable portions of the Dome Rock Mountains to the east and sky (higher quality landscape features). The resulting view blockage would be moderate.

Overall Visual Change

From KOP 2, the overall visual change caused by the proposed project would be moderate-to-high due to the moderate-to-high degree of visual contrast, dominant project structures, and moderate degree of view blockage caused by project structures.

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 2 would cause adverse but less than significant visual impact.

KOP 3 – Mesa Verde (Nichols Warm Springs)

Visual Resources Figure 7B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 3 on the north side of the Mesa Verde residential subdivision, approximately 2.5 miles southwest of the project site. The geometric block forms of the proposed power plant facilities are visible to the right of the existing BEP I facilities.

Visual Contrast

The proposed project would add the slightly noticeable geometric forms and complex lines of the HRSG structures, stacks, and eight-cell cooling tower to the existing landscape. From the vantage point of KOP 3, these structural characteristics would generally be consistent with existing forms and lines established by the BEP I structural features though inconsistent with the more horizontal to irregular forms and lines of the mesa landforms and vegetation respectively. The neutral color of the proposed facilities would also be consistent with the color of the existing BEP I facilities. The resulting visual contrast would be low (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The most prominent landscape feature in foreground to middleground views from KOP 3 is the broad mesa landform. At the KOP 3 viewing distance of approximately 2.5 miles, the barely noticeable geometric, block forms of the proposed project would appear as subordinate, background features in the landscape.

View Blockage

As viewed from KOP 3, the small profile of the proposed project and minimal skylining that would occur would result in a low degree of view blockage.

Overall Visual Change

From KOP 3, the values for visual contrast, project dominance, and view blockage, when taken together, constitute a low level of overall visual change.

Visual Impact Significance

When considered within the context of the moderate visual sensitivity of the existing landscape and viewing characteristics, the low visual change that would be perceived from KOP 3 would not result in a significant visual impact.

KOP 4 – Central Blythe

Visual Resources Figure 8B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 4 adjacent to the “C” Canal Levee at Hobsonway, approximately four miles east of the project site near central Blythe. From this location, the proposed project facilities would not be discernible in the landscape due to the screening provided by intervening vegetation.

Visual Contrast

No visual contrast would occur since the proposed project facilities would not be discernible from this KOP (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

Because the proposed project components would not be visible at this location, project dominance would be rated none.

View Blockage

From Key Observation Point 4, there would be no view blockage since the Project components would not be visible.

Overall Visual Change

From KOP 4, there would be no visual change because of the lack of project visibility.

Visual Impact Significance

From KOP 4, no significant visual impacts are anticipated given the lack of project visibility due to the substantial viewing distance and the screening provided by intervening vegetation.

KOP 5 – Blythe Municipal Golf Course and Residences

Visual Resources Figure 9B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 5 at the Blythe Municipal Golf Course and adjacent residences. The geometric block forms of the proposed power plant facilities would be slightly noticeable on the mesa horizon as a low rectangular structure with a vertical component extending above. At a distance of approximately 4.5 miles, no other project components (transmission lines, switchyard, and evaporation ponds) would be discernible.

Visual Contrast

The proposed project would be barely discernible as background geometric block and linear forms. To the extent they are visible, the structural characteristics would be consistent with the BEP I features and overall visual contrast as experienced from KOP 5 would be low. (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The most prominent landscape features in foreground to middleground views from KOP 5 are the broad landforms of the valley floor and mesa. The background is dominated by the distant angular forms of the Mule, Palo Verde, and Little Chuckwalla Mountains. At the KOP 5 viewing distance of approximately 4.5 miles, the geometric, block forms of the proposed project would appear small in size in the wide field of view, similar to BEP I, and subordinate in relation to the level valley and mesa and mountainous backdrop.

View Blockage

As viewed from KOP 5, the small profile of the proposed project would result in minimal blockage of the mountain backdrop and overall view blockage would be low.

Overall Visual Change

From KOP 5, the overall visual change caused by the proposed project would be low due to the low degree of contrast and view blockage that would result from the project's visually subordinate structures.

Visual Impact Significance

When considered within the context of the overall moderate-to-high visual sensitivity of the existing landscape and viewing characteristics, the low visual change that would be perceived from KOP 5 would result in an adverse but not significant visual impact.

KOP 6 – Westbound Hobsonway

Visual Resources Figure 10B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 6 on westbound Hobsonway at the intersection of Hobsonway and Buck Boulevard. The most obvious change to the landscape would be the visibility of the HRSG structures and stacks and the eight-cell cooling tower.

Visual Contrast

The proposed project would add a prominent industrial facility to the foreground landscape. While the neutral colors and complex geometric forms and lines of the HRSG structures, stacks, and cooling tower would be consistent with the forms, lines, and colors established by the existing BEP I facilities, they would contrast with the simple horizontal landforms of the mesa landscape and irregular forms and lines of the background mountain ranges. The resulting visual contrast would be moderate-to-high (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The proposed industrial facilities would be spatially prominent in the primary cone of vision of westbound travelers on Hobsonway. The structural mass and scale would appear larger than BEP I and equally prominent compared to the background mountain ranges due to the proposed project's close proximity to Hobsonway. The solid massing of the geometric block structures and the structure skylining would increase the prominence of the proposed structures in the wide field of view. As a result, the proposed project would appear co-dominant-to-dominant in the context of the existing natural landforms and built features.

View Blockage

From KOP 6, project structures (lower quality landscape features) would block from view a substantial portion of the background mountain range (higher quality landscape feature). The resulting view blockage would be moderate.

Overall Visual Change

From KOP 6, the overall visual change caused by the proposed project would be moderate-to-high due to the moderate-to-high degree of visual contrast, co-dominant-to-dominant project dominance, and moderate view blockage that would result from the project's structures.

Visual Impact Significance

When considered within the context of the overall low-to-moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 6 would cause an adverse but not significant visual impact.

KOP 7 – Westbound Interstate 10

The most obvious change to the landscape would be the addition of the structurally complex HRSG structures and stacks and the eight-cell cooling tower.

Visual Contrast

The proposed project would add a prominent industrial facility to the foreground landscape. While the neutral colors and complex geometric forms and lines of the HRSG structures, stacks, and cooling tower would be consistent with the forms, lines, and colors established by the existing BEP I facilities, they would contrast with the simple horizontal mesa landform and irregular forms and lines of the background mountain ranges. The resulting visual contrast would be moderate-to-high (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The proposed industrial facilities would be spatially prominent in the primary cone of vision of westbound travelers on I-10. The mass and scale of the proposed structures would appear greater than the existing BEP I structures and equally prominent compared to the background mountain ranges given the closer proximity of BEP II to I-10. The solid massing of the complex, geometric block structures and the structure skylining would increase the prominence of the proposed structures in the wide field of view. As a result, the proposed project would appear co-dominant to dominant in the context of the existing natural landforms and built features.

View Blockage

From KOP 7, project structures (lower quality landscape features) would block from view a substantial portion of the background mountain range (higher quality landscape feature). The resulting view blockage would be moderate in the wide field of view.

Overall Visual Change

From KOP 7, the overall visual change caused by the proposed project would be moderate-to-high due to the moderate-to-high degree of visual contrast, co-dominant-to-dominant project dominance, and moderate view blockage that would result from the project's structures.

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 7 would cause an adverse but less than significant visual impact.

<u>Linear facilities</u>

The proposed linear facilities interconnections (aboveground electric and underground gas, water, and brine return) would all occur onsite and would not result in significant visual impacts.

Lighting

At present, the most prominent sources of light in the vicinity of the BEP II site are the adjacent BEP I facility and the nearby motor vehicle lights on I-10. In regard to exterior lighting, the applicant has stated the following:

"The lighting system will provide illumination for plant operation under normal conditions and also emergency lighting to perform manual operations during outage of the normal power source. The lighting system will include high pressure (HP) sodium light sources for outdoor installations. A low visibility lighting scheme using shielded, high cut-off angle fixtures will be utilized to minimize the nighttime impact [on] nearby properties.

> The area lighting system will provide illumination for the performance of general outdoor yard tasks, safety, plant security and general site roadway access and will consist of HP sodium luminaries and support poles. Access roads from Buck Boulevard through the plant will be illuminated. The Project has agreed with the City of Blythe to provide street lighting along Buck Boulevard and Hobsonway." (BEP II 2002a, pp. 7.5-17-18).

Although lighting of project facilities would not be required under FAA guidelines, the Applicant has decided to install FAA approved lighting at the tops of the HRSG exhaust stacks (BEP II 2002a, p. 7.5-17).

In order to control lighting impacts, the Applicant has indicated that the lighting system would be designed to minimize its impact on surrounding areas and would include such control measures as timers, sensors, and/or switches to keep lights off when they are not needed (BEP II 2002a, pp. 7.5-17-18).

Project night lighting would be visible from several of the KOPs and their represented areas (KOPs 1, 2, 3, 5, 6, and 7). Given the limited amount of night lighting in the vicinity of the power plant site, the proposed project lighting has the potential to further change the character of the existing landscape at night both during construction and operation of the project, potentially resulting in significant visual impacts. Even shielded lighting elements could create significant light and glare impacts as a result of indirect lighting of project structures and backscatter if not properly managed.

Water Conservation Offset Plan

Implementation of the WCOP would result in changes to the agricultural use of some lands in the vicinity of the proposed project. However, no information has been provided as to which currently cultivated lands might be fallowed (taken out of production). Regardless, given the sporadic appearance of agricultural lands across the regional landscape, it is unlikely that changes to existing cultivation patterns in the landscape would be noticeable to passing travelers on I-10 and it is unlikely that changes in cultivation patterns visible from residential uses or local roads would cause a noticeable change in the existing visual quality of a given landscape.

Visible Plumes

A separate Visible Plume Modeling Analysis, included herein as Appendix VR-4, has determined that visible plumes from the BEP II project will not exceed Energy Commission staff's 10 percent frequency threshold. Visible plumes occurring less than 10 percent are considered to be less than significant.

CONSIDERATION OF IMPACTS IN RELATION TO CEQA SIGNIFICANCE CRITERIA

This analysis considered the potential impacts of the proposed project in relation to the four significance criteria for visual resource impacts listed in Appendix G of the CEQA Guidelines, under Aesthetics, specified below.

1. Would the project have a substantial adverse effect on a scenic vista?

Although panoramic vistas are available to users of the Blythe Municipal Golf Course and to the adjacent residences at Mesa Bluffs, there are no recognized scenic vistas in the project viewshed. Therefore, the project would not cause significant visual impacts in regard to this criterion.

2. Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?

The foreground to middleground mesa landscape consists primarily of desert scrub vegetation with a substantial amount of electric transmission infrastructure and other built features (including roads and structures). Views from the nearby residences off of Hobsonway and from Hobsonway and I-10 are not considered scenic. Therefore, the project would not cause significant visual impacts in regard to this criterion.

3. Would the project substantially degrade the existing visual character or quality of the site and its surroundings?

As discussed in a previous section of this analysis, the proposed project would introduce prominent structures with industrial character into the foreground to middleground views from I-10, Hobsonway, and a nearby residence. The resulting visual change would range from low to moderate-to-high depending on viewpoint location. Eastbound travelers on Hobsonway (represented by KOP 2) and westbound travelers on I-10 (represented by KOP 7) would experience adverse, but less than significant visual impacts under this criterion.

4. Would the project create a new source of substantial light or glare that would adversely affect daytime or nighttime views in the area?

The project has the potential to create a new source of substantial light that would adversely affect nighttime views in the area and result in a significant visual impact under this criterion.

CUMULATIVE IMPACTS

Cumulative impacts to visual resources could occur where project facilities or activities (such as construction) occupy the same field of view as other built facilities or impacted landscapes. It is also possible that a cumulative impact could occur if a viewer's perception is that the general visual quality of an area is diminished by the proliferation of visible structures (or construction effects such as disturbed vegetation), even if the new structures are not within the same field of view as the existing structures. The significance of the cumulative impact would depend on the degree to which (1) the viewshed is altered; (2) visual access to scenic resources is impaired; (3) visual quality is diminished; or (4) the project's visual contrast is increased.

VISUAL RESOURCES Table 2 lists the two projects that have been identified for cumulative impact analysis – BEP I and the Desert Southwest Transmission Line Project (including the Hobsonway Substation and the transmission line).

VISUAL RESOURCES Table 2
List of Cumulative Projects

Project	Description	Visible in Proposed Project Field of View	Cumulative Impact and Significance
Blythe Energy Project Phase I	Combined Cycle Power Plant	YES KOPs 1, 2, 3, 5, 6, and 7 --------------- NO KOP 4	Substantial increase in industrialization of the Desert Mesa landscape.
Desert Southwest Transmission Line Project: Hobsonway Substation	A 230 or 500 kV Transmission Line Substation to be located immediately adjacent and to the west of BEP II.	YES KOPs 1, 2, 3, 5, 6, and 7 --------------- NO KOP 4	Substantial increase in industrialization of the Desert Mesa landscape.
Desert Southwest Transmission Line Project: Proposed Transmission Line Route	A proposed 118-mile 230 or 500 kV Transmission Line extending from the proposed Hobsonway Substation to the existing Devers Substation north of Palm Springs. The route would parallel existing facilities in the I-10 corridor for much of the route	PARTIALLY KOPs 1, 2, 3, 6, and 7	Introduction of substantial structural visual contrast into the desert landscape visible from I-10 between Desert Center and the route's I-10 crossing just east of the Cactus City Rest Area.

BEP II would be visible within the same field of view as BEP I and would make a substantial additional contribution to the visual impact resulting from BEP I. BEP II is closer than BEP I to Hobsonway, the nearby residence, and I-10. As a result, BEP II would appear larger in scale and more prominent. The two projects combined would present an expansive area of complex industrial character in an otherwise desert mesa landscape. The visual contrast, structural dominance, and view blockage resulting from the combined projects would cause a cumulative visual impact, however based on the duration of view for travelers on 1-10 and low number of viewers on Hobsonway, the proposed project's contribution to that impact would not be cumulatively considerable. In addition, the proposed Hobsonway Substation that would be part of the Desert Southwest Transmission Line Project would be located immediately to the west of BEP II. This facility would increase the cumulative visual impact of BEP I and BEP II by adding still more industrial character to the landscape.

The 230 or 500 kV Transmission Line of the Desert Southwest Transmission Line Project would also contribute industrial character to the I-10 corridor, particularly along the section of I-10 west of Desert Center to the transmission line's crossing of I-10, just east of the Cactus City Rest Area. Along this portion of the route, the transmission line would cause an adverse but less than significant visual impact as it closely parallels I-10. An existing transmission line passes substantially further to the south. This section of the transmission line would cause an adverse but less than significant direct visual impact, as well as, contribute to a cumulative visual impact that although adverse would be less than significant considering the low-to-moderate visual quality and moderate viewer exposure.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II project (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and Census 1990 information that shows the low-income population is less than fifty percent within the same radius. Based on the visual resources analysis, and as discussed below, staff has determined that all significant direct or cumulative impacts resulting from the construction or operation of the project will be mitigated, and therefore there are no visual resources environmental justice issues related to this project.

FACILITY CLOSURE

There are at least three circumstances in which a facility closure can take place, planned closure, unexpected temporary closure and unexpected permanent closure. Closure requirements are discussed in more detail in the General Conditions section of this FSA.

Planned closure occurs at the end of a project's life, when the facility is closed in an anticipated, orderly manner, at the end of its useful economic or mechanical life, or due to gradual obsolescence. The closure plan that the project owner is required to prepare will address removal of the power plant structures.

Unexpected temporary closure occurs when the facility is closed suddenly and/or unexpectedly, on a short-term basis, due to unforeseen circumstances such as a natural disaster or an emergency.

Unexpected permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly on a permanent basis. This includes unexpected closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unexpected closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned. The contingency plan that the project owner is required to prepare would address removal of the power plant structures. No special conditions regarding visual resources are expected to be required to address any of the three types of closure.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

LOCAL

Riverside County

Under Program 2 – County Scenic Highways of the Scenic Highways portion of the Comprehensive General Plan, I-10 is identified as eligible for designation as a County Scenic Highway. Although there are a number of land use standards pertaining to scenic highways in the Comprehensive General Plan, these standards only address official State Scenic Highways, State Scenic Highway Corridors, and designated scenic highway routes. They do not pertain to highways that are eligible but not yet designated, which is the case for that portion of I-10 in the vicinity of the proposed project. Therefore, the proposed project is considered consistent with the Riverside County Comprehensive General Plan with respect to visual resources.

City of Blythe

The proposed project is required to provide landscaping per the City of Blythe Zoning Ordinance. Staff has proposed condition of certification VIS-3 that requires specific landscaping to minimize adverse visual impacts.

MITIGATION

APPLICANT'S PROPOSED MITIGATION MEASURES

The applicant has proposed seven mitigation measures to be incorporated into the project design to minimize visual impacts associated with the operation of the facility:

Plant facilities will be painted with colors similar to the surrounding desert landscape, principally tan, sand, and buff colors. The colors will help project facilities to harmonize with the surrounding environment.

1. Fencing will be constructed of non-reflective material, treated, or painted to reduce visual effects.
2. Non-reflective surfaces will be used for plant equipment and structures, including transmission line structures, to minimize glare from these facilities.
3. Nighttime lighting on the project site will be limited to areas required for the safety of project personnel and the public.
4. Directional shielding of lights will be installed to prevent significant light, glare, or backscatter illumination visible to sensitive viewpoints.

5. Exposed soils resulting from vegetation clearing during construction must be revegetated after facilities are installed.
6. All construction debris will be removed immediately following completion of power plant and switchyard construction activities.

ADDITIONAL MITIGATION PROPOSED BY STAFF

Energy Commission staff have identified potential significant visual impacts resulting from visibility of project structures and night lighting. Although staff generally agrees with the applicant's proposals to mitigate project structure and lighting impacts, staff's position is that some of these mitigation measures need to be more precisely developed and, in some cases, expanded in conditions of certification to ensure mitigation of these potential impacts to less than significant levels. Staff has proposed conditions of certification to mitigate potential significant project impacts. Without such conditions staff cannot state that the project would not cause significant visual impacts.

Applicant's Mitigation Measure 1 regarding structure color is included in Condition of Certification **VIS-2**. Applicant's Mitigation Measures 2 and 3 regarding non-reflective surfaces are included in Condition of Certification **VIS-2**. Applicant's Mitigation Measures 4 and 5 regarding lighting are included in Condition of Certification **VIS-5**. Applicant's Mitigation Measures 6 and 7 regarding exposed soils and construction debris are included in Condition of Certification **VIS-1**.

Mitigation of Construction Impacts

Construction of the proposed power plant and associated facilities would result in adverse visual impacts. Staff has proposed mitigation in Condition of Certification **VIS-1** to ensure that visual impacts resulting from project construction do not become significant.

The project owner shall ensure that visual impacts of project construction are adequately mitigated. The project owner shall require from its contractors that all facility construction sites and staging, material, and equipment storage areas be visually screened from adjacent public roads and nearby residences. Upon completion of construction, all evidence of project construction activities, including debris shall be removed and ground disturbance due to construction activities and staging and storage areas shall be remediated to its pre-construction condition. Any vegetation removed in the course of construction that is not replaced by project features or landscaping will be replaced on a one-to-one, in-kind basis as appropriate. Such replacement planting shall be monitored for a period of three years to ensure survival. During this period, all dead plant material shall be replaced.

Effective implementation of Condition of Certification **VIS-1** will minimize the intrusiveness of project construction and keep construction visual impacts to less than significant levels.

Mitigation of Impacts of Proposed Structures

As presently proposed, the project's structures would result in adverse visual impacts when viewed from nearby roads and a residence. Staff has proposed mitigation in

Conditions of Certification **VIS-2** and **VIS-3** to enhance the effectiveness of the Applicant's Mitigation Measure 1 and to help blend project structures with the existing landscape:

Prior to first fire, the project owner shall treat all project structures, buildings, and fences in appropriate colors or hues that minimize visual intrusion and contrast by blending with the landscape, such that those structures, buildings, and fences have surfaces that do not create glare; and such that they are consistent with local laws, ordinances, regulations, and standards. The selection of colors must not contrast substantially with the colors applied to the BEP I project. The project owner shall submit for Compliance Project Manager (CPM) review and approval, a specific treatment plan whose proper implementation will satisfy these requirements (see Condition of Certification **VIS-2**).

The project owner shall also provide landscaping that is effective in improving the appearance of the proposed project. Two offset rows of native trees shall be planted along the western, southern (Hobsonway), and southern half of the eastern (Buck Boulevard) BEP property boundaries. The inner row (closest to the proposed project) should be California Fan Palms. The outer row must be dense foliage native trees. The project owner shall submit for CPM review and approval, a specific landscaping plan whose proper implementation will satisfy these requirements (see Condition of Certification **VIS-3**).

Mitigation of Project Lighting Impacts

As previously discussed, the proposed project lighting has the potential to change the character of the existing landscape at night both during construction and operation of the project and could result in significant visual impacts to nearby motorists and a residence. Therefore, staff proposes mitigation in Conditions of Certification **VIS-4** and **VIS-5** to mitigate project night lighting impacts.

The project owner shall ensure that lighting for construction of the power plant and linear facilities is used in a manner that minimizes potential night lighting impacts. The project owner shall mitigate impacts of night lighting for construction as specified in Condition of Certification **VIS-4**.

The project owner shall design and install all permanent lighting such that light bulbs and reflectors are not visible from public viewing areas, lighting does not cause reflected glare, and illumination of the project, the vicinity, and the nighttime sky is minimized. The project owner shall submit for CPM review and approval, a specific lighting plan whose proper implementation will satisfy these requirements (see Condition of Certification **VIS-5**).

Effective implementation of Conditions of Certification **VIS-4** and **VIS-5** will minimize lighting and keep lighting impacts to less than significant levels.

Mitigation of Water Conservation Offset Plan Impacts

Staff does not anticipate a need for any mitigation for visual impacts as a result of the proposed WCOP.

Mitigation of Impacts in Relation to CEQA Significance Criteria

The proposed project has the potential to cause significant visual impacts with respect to two of the four CEQA significance criteria. The applicant's Mitigation Measures 1 through 3 would require the use of materials that limit glare and the use of flat, neutral-tone finishes to blend project structures with the surrounding landscape. Staff's Condition of Certification **VIS-2** further augments the requirements for structural treatment and finishes. Staff's Condition of Certification **VIS-3** requires landscaping to improve the appearance of the proposed project. Effective implementation of the applicant's proposed mitigation measures as augmented by staff's conditions of certification would ensure that the visual impacts of project structures under Criterion 3, although adverse, do not reach significant levels.

The project's night lighting during construction and operation has the potential to create a new source of substantial light that would adversely affect nighttime views in the area and result in a significant visual impact under Criterion 4. However, the exterior lighting control measures proposed in the Applicant's Mitigation Measures 4 and 5 and augmented in staff's Conditions of Certification **VIS-4** and **VIS-5** would ensure that lighting impacts would be less than significant with regard to Criterion 4.

Mitigation of Cumulative Impacts

As previously discussed, the cumulative impact of the proposed project would be cumulatively considerable in conjunction with the existing BEP I power plant and the proposed Desert Southwest Transmission Line Project Substation on Hobsonway. Staff has proposed two mitigation measures and two conditions of certification (**VIS-2** and **VIS-3**) to reduce the direct adverse visual impact of project structures and to reduce the project's cumulative visual impact to less than considerable.

Furthermore, although the proposed project has the potential to contribute considerably to cumulative lighting impacts, applicant and staff's proposed mitigation measures, required by staff's proposed conditions of certification **VIS-4** and **VIS-5**, would keep the project's contribution to cumulative lighting impacts to a less than considerable level.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff concludes that the project, as proposed, has the potential to cause adverse and significant visual impacts. However, with effective implementation of staff's additional mitigation measures and conditions of certification for painting, landscaping and lighting control, the project's visual impacts would be less than significant.

Staff has also concluded that the project's contribution to cumulative visual and lighting impacts would be cumulatively considerable, based on effective implementation of staff's additional mitigation measures and conditions of certification.

Since the proposed project would not cause significant visual impacts on minority populations, there would be no environmental justice issues for visual resources.

RECOMMENDATIONS

The Energy Commission should adopt the following conditions of certification if it approves the project.

PROPOSED CONDITIONS OF CERTIFICATION

Construction Screening and Surface Restoration

VIS-1 To minimize the visual impacts of project construction, the project owner shall screen the project site, including staging areas and material and storage areas, from public views from nearby residences and public roadways.

Upon completion of project construction the project owner shall remove all evidence of construction activities, including ground disturbance due to staging and storage areas and pipeline construction, and shall restore all disturbed areas.

The project owner shall submit to the CPM for review and approval and to the City of Blythe for review and comment a specific screening and surface restoration plan whose proper implementation will satisfy these requirements.

The project owner shall not implement the screening and surface restoration plan until receipt of written approval from the CPM.

Verification: At least 90 days prior to the start of site mobilization, the project owner shall submit a Screening and Surface Restoration Plan (Plan) to the CPM for review and approval and to the City of Blythe for review and comment. The project owner shall install the screening prior to the start of site mobilization for the power plant. The project owner shall notify the CPM within seven days after installing the screening that it is ready for inspection. The project owner shall complete surface restoration before the start of commercial operation. The project owner shall notify the CPM within seven days after completing the surface restoration that it is ready for inspection.

SURFACE TREATMENT OF PROJECT STRUCTURES AND BUILDINGS

VIS-2 Prior to first turbine roll, the project owner shall treat all project structures, buildings, and fences in appropriate colors or hues that minimize visual intrusion and contrast by blending with the landscape, such that those structures, buildings, and fences have surfaces that do not create glare. The selection of colors must not contrast substantially with the colors applied to the BEP I project. The project owner shall submit for CPM review and approval, a specific treatment plan whose proper implementation will satisfy these requirements. The treatment plan shall include:

a) Specification, and 11” x 17” color simulations at life size scale, of the treatment proposed for use on project structures, including structures treated during manufacture;

b) A list of each major project structure, building, tank, transmission line tower and/or pole, and fencing specifying the color(s) and finish proposed for each (colors must be identified by name and by vendor brand or a universal designation);

c) Two sets of brochures and/or color chips for each proposed color;

d) Samples approximately 6” x 9” of each proposed treatment and color on each surface material to which they would be applied that would be visible to the public;

e) A detailed schedule for completion of the treatment; and

f) A procedure to ensure proper treatment maintenance for the life of the project.

Verification: The project owner shall not specify to the vendors the treatment of any buildings or structures treated during manufacture, or perform the final treatment on any buildings or structures treated on site, until the project owner receives notification of approval of the treatment plan by the CPM.

The project owner shall submit its proposed treatment plan at least 90 days prior to ordering the first structures that are color treated during manufacture. Within 30 days following the start of commercial operation, the project owner shall notify the CPM that all buildings and structures are ready for inspection. The project owner shall provide a status report regarding treatment maintenance in the Annual Compliance Report.

LANDSCAPING

VIS-3 The project owner shall provide landscaping that improves the appearance of the proposed project. Two offset rows of trees shall be planted along the western, southern (Hobsonway), and southern half of the eastern (Buck Boulevard) BEP property boundaries. The inner row (closest to the proposed project) should be native California Fan Palms. The outer row must be comprised of dense foliage native trees.

The project owner shall submit the landscaping plan to the CPM for review and approval and to the City of Blythe for review and comment. The plan shall include but not necessarily be limited to:

a) An 11”x17” color simulation of the proposed landscaping at 5 years as viewed from KOP 3;

b) A plan view to scale depicting the project and the location of landscaping;

c) A detailed list of plants to be used; their size and age at planting; the expected time to maturity, and the expected height at five years and at maturity.

Verification: Prior to first turbine roll and at least 90 days prior to installing the landscaping, the project owner shall submit the landscaping plan to the CPM for review and approval and to the City of Blythe for review and comment.

If the CPM notifies the project owner that revisions of the submittal are needed before the CPM will approve the submittal, within 30 days of receiving that notification, the project owner shall prepare and submit to the CPM a revised submittal.

The project owner shall complete installation of the landscaping prior to the start of commercial operation. The project owner shall notify the CPM within seven days after completing installation of the landscaping, that it is ready for inspection.

CONSTRUCTION LIGHTING

VIS-4 The project owner shall ensure that lighting for construction of the power plant is used in a manner that minimizes potential night lighting impacts, as follows:

a) All lighting shall be of minimum necessary brightness consistent with worker safety.

b) All fixed position lighting shall be shielded, hooded, and directed downward to minimize backscatter to the night sky and direct light trespass (direct lighting extending outside the boundaries of the construction area).

c) Wherever feasible and safe, lighting shall be kept off when not in use and motion detectors shall be employed.

d) A lighting complaint resolution form (following the general format of that in Appendix VR-2) shall be used by plant construction management, to record all lighting complaints received and to document the resolution of that complaint.

Verification: Within seven days after the first use of construction lighting, the project owner shall notify the CPM that the lighting is ready for inspection.

If the CPM notifies the project owner that modifications to the lighting are needed to minimize impacts, within 15 days of receiving that notification the project owner shall implement the necessary modifications and notify the CPM that the modifications have been completed.

The project owner shall report any lighting complaints and documentation of resolution in the Monthly Compliance Report, accompanied by any lighting complaint resolution forms for that month.

PERMANENT LIGHTING

VIS-5 The project owner shall design and install all permanent lighting such that light bulbs and reflectors are not visible from public viewing areas; lighting does not cause reflected glare; and illumination of the project, the vicinity, and the nighttime sky is minimized. To meet these requirements the project owner shall submit a lighting mitigation plan that includes but is not necessarily limited to the following:

a) Lighting shall be designed so exterior light fixtures are hooded, with lights directed downward or toward the area to be illuminated and so that backscatter to the nighttime sky is minimized. The design of the lighting shall be such that the luminescence or light source is shielded to prevent light trespass outside the project boundary;

b) All lighting shall be of minimum necessary brightness consistent with worker safety;

c) High illumination areas not occupied on a continuous basis (such as maintenance platforms) shall have switches or motion detectors to light the area only when occupied;

A lighting complaint resolution form (following the general format of that in Appendix VR-2) shall be used by plant operations to record all lighting complaints received and document the resolution of those complaints. All records of lighting complaints shall be kept in the on-site compliance file.

Verification: At least 90 days prior to ordering any permanent exterior lighting, the project owner shall contact the CPM to arrange a meeting to discuss the documentation required in the lighting mitigation plan.

At least 60 days prior to ordering any permanent exterior lighting, the project owner shall submit to the CPM for review and approval a plan that describes the measures to be used and demonstrates that the requirements of the condition will be satisfied. The project owner shall not order any exterior lighting until it receives CPM approval of the lighting mitigation plan.

Prior to initial firing, the project owner shall notify the CPM that the lighting has been completed and is ready for inspection.

The project owner shall report any complaints about permanent lighting and provide documentation of resolution in the Annual Compliance Report.

REFERENCES

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Caithness BEP II, LLC/Looper (tn: 26118). 2002a. Revised Application for Certification, Volume 2 (02-AFC-1). Submitted to the California Energy Commission on July 9, 2002.

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Appendix VR – 1
Blythe Energy Project II Visual Resources Staff Assessment - Summary of Analysis
(Does Not Include Plume Analysis)

VIEWPOINT		EXISTING VISUAL SETTING							VISUAL CHANGE					IMPACT SIGNIFICANCE	
				Viewer Exposure											
Key Observation Point (KOP)	Description	Visual Quality	Viewer Concern	Visibility	Number of Viewers	Duration of View	Overall Viewer Exposure	Overall Visual Sensitivity	Description of Visual Change	Visual Contrast	Project Dominance	View Blockage	Overall Visual Change	Mitigation / Conditions	Impact Significance with Mitigation
KOP 1 **EASTBOUND INTERSTATE 10** **Figures 5A / 5B**	View to the northeast from eastbound I-10, approximately 0.3 mi. southwest of the project site.	**Low to Moderate** Foreground to middleground level, desert mesa landscape lacking distinctive features and dominated by energy generation and transmission infrastructure and Interstate 10. The immediate landscape lacks scenic features or elements of visual interest. Portions of background mountains are blocked by the industrial forms of the existing BEP I.	**Low to Moderate** Travelers on I-10 anticipate a foreground to middleground desert landscape dominated by energy infrastructure with a prominent presence of the rectangular block forms of trucks and containers on I-10. An increase in industrial character or view blockage would be seen as an adverse visual change.	**High**	**High**	**Moderate**	**Moderate to High**	**Moderate**	Addition of noticeable geometric forms with horizontal to vertical lines and complex industrial character. Facilities would be visible and co-dominant at this foreground viewing distance.	**Low to Moderate**	**Co-Dominant**	**Low to Moderate**	**Low to Moderate**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**Adverse but Not Significant**
KOP 2 **EASTBOUND HOBSONWAY** **Figures 6A / 6B**	View to the east-northeast from eastbound Hobsonway, approximately 0.4 mi. west of the project site.	**Low to Moderate** Foreground to middleground level, desert mesa landscape lacking distinctive features and dominated by energy generation and transmission infrastructure and Hobsonway. The immediate landscape lacks scenic features or elements of visual interest. Portions of background mountains are blocked by the industrial forms of the existing BEP I and transmission infrastructure.	**Low to Moderate** Travelers on this stretch of Hobsonway anticipate a foreground to middleground non-descript desert landscape with prominent energy infrastructure. However, any increase in industrial character would be seen as an adverse visual change.	**High**	**Low**	**Extended**	**Moderate to High**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass and scale would be greater than existing BEP I structures.	**Moderate to High**	**Dominant**	**Moderate**	**Moderate to High**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**Adverse but Not Significant**
KOP 3 **MESA VERDE (Nichols Warm Springs)** **Figures 7A / 7B**	View to the northeast from the north side of the Mesa Verde residential subdivision, approximately 2.5 mi. southwest of the project site.	**Low to Moderate** Foreground to middleground level, monotone desert mesa landscape, lacking distinctive features or elements of visual interest. Prominent energy and transportation infrastructure.	**Moderate** Although residences are generally attributed a higher degree of viewer sensitivity, in this case, viewer expectations are tempered by the visibility of the intervening I-10 corridor and electric transmission lines, and the visibility of the existing BEP and facilities associated with Blythe Municipal Airport.	**Low**	**Low to Moderate**	**Extended**	**Moderate**	**Moderate**	Addition of minimally noticeable geometric forms. Structural mass would be similar to BEP I. Facilities would be visible but subordinate at this background viewing distance.	**Low**	**Subordinate**	**Low**	**Low**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**Adverse but Not Significant**
KOP 4 **CENTRAL BLYTHE** **Figures 8A / 8B**	View to the west "C" Canal Levee at Hobsonway, approximately 4 mi. east of the project site near central Blythe.	**Low to Moderate** Foreground to middleground level, agricultural landscape consisting of fields, roads, and utility infrastructure. Generally lacking distinctive features or elements of visual interest.	**Low** Viewers near this location would be accessing commercial facilities at the adjacent commercial center. Viewer expectations would include the transitional landscape between urban and rural settings that include various forms of infrastructure as well as agricultural and commercial uses.	**Low**	**Moderate to High**	**Brief to Moderate**	**Moderate**	**Low to Moderate**	No visible change.	**None**	**None**	**None**	**None**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**None**
KOP 5 **BLYTHE MUNICIPAL GOLF COURSE & RESIDENCES** **Figures 9A / 9B**	View to the southwest from Blythe Municipal Golf Course, approximately 4.5 mile northwest of the project site.	**Moderate to High** Panoramic vista views overlooking the Palo Verde Valley and Palo Verde Mesa backdropped by distant mountains. Elevated perspective provides visual access to a regional landscape that offers more distinctive features with greater visual variety and interest.	**Moderate to High** Residents in the Mesa Bluffs area are situated along the edge of the bluff to take advantage of the vista views of a predominantly agricultural and naturally appearing landscape with few structural features.	**Low**	**Moderate**	**Extended**	**Moderate**	**Moderate to High**	Addition of minimally noticeable geometric forms. Structural characteristics and mass would be similar to BEP I facilities and would appear subordinate at this background viewing distance.	**Low**	**Subordinate**	**Low**	**Low**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**Adverse but Not Significant**
KOP 6 **WESTBOUND HOBSONWAY** **Figures 10A / 10B**	View to the northwest from westbound Hobsonway, at the intersection of Hobsonway and Buck Boulevard.	**Low to Moderate** Foreground level, highly modified desert mesa dominated by energy generation and transmission infrastructure. The immediate landscape lacks scenic features or elements of visual interest. Portions of background mountains are blocked by the industrial forms of the existing BEP I.	**Low to Moderate** Travelers along Hobsonway generally anticipate open, minimally obstructed views though viewer expectations will now be conditioned by the prominent industrial presence of the BEP I. A noticeable increase in visible industrial or additional view blockage would be perceived as an adverse visual change.	**High**	**Low**	**Moderate to Extended**	**Moderate**	**Low to Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass and scale would appear greater than the existing facilities due to the close proximity of BEP II to Hobsonway.	**Moderate to High**	**Co-dominant to Dominant**	**Moderate**	**Moderate to High**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**Adverse but Not Significant**

APPENDIX VR – 1
BLYTHE ENERGY PROJECT II VISUAL RESOURCES STAFF ASSESSMENT - SUMMARY OF ANALYSIS
(DOES NOT INCLUDE PLUME ANALYSIS)

VIEWPOINT		EXISTING VISUAL SETTING							VISUAL CHANGE					IMPACT SIGNIFICANCE	
Key Observation Point (KOP)	Description	Visual Quality	Viewer Concern	Viewer Exposure: Visibility	Viewer Exposure: Number of Viewers	Viewer Exposure: Duration of View	Viewer Exposure: Overall Viewer Exposure	Overall Visual Sensitivity	Description of Visual Change	Visual Contrast	Project Dominance	View Blockage	Overall Visual Change	Mitigation / Conditions	Impact Significance with Mitigation
KOP 7 **WESTBOUND INTERSTATE 10** **Figure 11**	View to the northwest from westbound Interstate 10, approximately 0.4 mile southeast of the project site.	**Low to Moderate** Foreground level, desert mesa with prominent energy generation and transmission infrastructure. The immediate landscape lacks scenic features or elements of visual interest. Small portions of the background mountains are blocked by the industrial forms of the existing BEP I.	**Low to Moderate** Travelers along I-10 generally anticipate open, minimally obstructed views though viewer expectations will now be conditioned by the prominent industrial presence of the BEP I. A noticeable increase in visible industrial or additional view blockage would be perceived as an adverse visual change.	**High**	**High**	**Moderate**	**Moderate to High**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass and scale would appear greater than the existing facilities due to the closer proximity of BEP II to I-10.	**Moderate to High**	**Co-dominant to Dominant**	**Moderate**	**Moderate to High**	**Applicant and Staff Measures & Staff's Conditions: VIS-2 VIS-3 VIS-5**	**Adverse but Not Significant**

APPENDIX VR – 2

LIGHTING COMPLAINT RESOLUTION FORM

Blythe Energy Project, Phase II City of Blythe, California
Complainant's name and address: Phone number:
Date complaint received: Time complaint received:
Nature of lighting complaint:
Definition of problem after investigation by plant personnel: Date complainant first contacted:
Description of corrective measures taken: Complainant's signature: ____________________ Date:
Approximate installed cost of corrective measures: $ Date installation completed: Date first letter sent to complainant: ____________(copy attached) Date final letter sent to complainant: ____________(copy attached)
This information is certified to be correct: Plant Manager's Signature:

(Attach additional pages and supporting documentation, as required.)

APPENDIX VR – 3

VISUAL RESOURCES FIGURES 1 THROUGH 11

APPENDIX VR – 4

VISIBLE PLUMES ANALYSIS

William Walters and Lisa Blewitt

INTRODUCTION

The following provides staff's assessment of the Blythe Energy Project Phase II (BEP II) cooling tower and heat recovery steam generator (HRSG) exhaust stack visible plumes. Staff completed a modeling analysis for the applicant's proposed unabated cooling tower and HRSG designs.

PROJECT DESCRIPTION

The applicant has proposed a linear 8-cell conventional mechanical-draft cooling towers. The applicant has not proposed to use any methods to abate visible plumes from the cooling towers.

The project includes two separate turbine/heat recovery steam generator systems, each with separate exhaust stacks. The turbines will be equipped with an evaporative inlet cooling system to increase plant output during periods of high ambient temperature conditions. Each HRSG has a duct burner sized to maintain the steam turbine generator maximum output at higher ambient conditions. Duct burner operation is expected to be approximately 2,500 hours per year during peak summer periods (May-September), for approximately 10 hours per day and five days per week. These duct burners will only operate at ambient temperatures of 50°F or greater due to steam turbine steam flow limitations (BEP II 2002b, DR #100). The applicant has not proposed to use any methods to abate visible plumes from the HRSG exhausts.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

EXISTING CONDITIONS

The applicant verified in Data Response (DR) #93 (BEP II 2002b) that the only other visible water vapor plume source in the vicinity of the project site is the water vapor plume from the Blythe Energy Project (BEP) cooling towers. BEP has a cooling tower as the main cooling system for the steam cycle, which is operated whenever the plant is dispatched. BEP also has a condenser tower for the inlet chilling system, which is operated whenever the ambient temperature is greater than 50°F. There are also minor steam plumes coming from miscellaneous steam vents, but these dissipate in relatively short distances.

COOLING TOWER DESIGN PARAMETERS

Staff evaluated the applicant's AFC (BEP II 2002a, AFC Sections 7.5.2.2.2 and 7.7.4.3) and Data Response #97 (BEP II 2002b), and performed an independent psychrometric analysis and dispersion modeling analysis to predict the frequency of visible plumes from the project's proposed unabated cooling tower.

The cooling tower design characteristics, presented below in **Table 1**, were determined through a review of the applicant's AFC and Data Request Responses, and through additional engineering calculations.

Table 1 –
New Cooling Tower Operating and Exhaust Parameters

Parameter		**New Cooling Tower Design Parameters**	
Number of Cells		8 (1 x 8 array)	
Stack Height		12.19 meters (40 feet)	
Cell Stack Diameter		10.07 meters (33 feet)	
Equivalent Stack Diameter		28.48 meters	
Maximum Design Inlet Air Flow Rate (kg/s)		6,068.1 (1)	
Tower Housing Length		144.1 meters (472 feet)	
Tower Housing Width		16.0 meters (52 feet)	
Maximum Heat Rejection Rate (MW)		328.03 (1)	
Design Liquid to Gas (L/G) Mass Ratio		1.26 (1)	
Case # (2)	**Ambient Condition**	**Exhaust Flow Rate (lbs/s/cell)**	**Exhaust Temperature (°F)**
1	95°F, 40% RH with Duct Firing	1570.5	95.8 (3)
2	59°F, 60% RH with Duct Firing	1699.0	80.8 (3)
3	30°F, 60% RH without Duct Firing	1795.1	66.1 (3)

Source: AFC (BEP II 2002a) Table 7.5-1 and Table 7.7-8, and Data Response, Set #1 (BEP II 2002b) DR #97.
Notes:
(1) For applicant modeling review purposes, the SACTI cooling tower design parameters were based on Case 2 (29°F, 60% RH, with Duct Firing).
(2) For CSVP modeling, values were extrapolated or interpolated between data points as necessary.
(3) Staff found, after performing a heat balance, that the exhaust temperatures provided by the applicant appeared to be in error. The exhaust temperature provided by the applicant for Case 1 appears to be too high and the temperatures provided for Cases 2 and 3 were too low. Staff's corrected estimates appear in the table.

For CSVP modeling, the exhaust temperature and exhaust mass flow rate values were calculated for the hourly ambient conditions modeled through linear interpolation and extrapolation of the data provided by the applicant for the three cases presented in **Table 1**. The exhaust moisture content was determined by assuming saturated conditions at the calculated exhaust temperature.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

Staff modeled the cooling tower plume frequency using the Combustion Stack Visible Plume (CSVP) model. **Table 2** provides the CSVP model visible plume frequency results using a three-year (1989-1991) meteorological data set, obtained from the National Climatic Data Center, from Blythe Airport.

Table 2 –
Staff Predicted Hours with Cooling Tower Steam Plumes
Blythe Airport 1989-1991 Meteorological Data

	Available (hr)	**Plume (hr)**	**Percent**
All Hours	26,280	3,793	14.4%
Daylight Hours	13,425	857	6.4%
Nighttime Hours	12,855	2,936	22.8%
Daylight No Rain/Fog Hours	13,265	790	6.0%
Seasonal Daylight No Rain/Fog Hours*	5,989	740	12.4%

*Seasonal conditions occur anytime from November through April.

These modeling results indicate that the visible plume formation would mainly occur during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. For the proposed cooling tower, the maximum temperature where a visible plume is predicted is 81°F when the relative humidity is 88%.

Staff reviewed the Applicant's dispersion modeling analysis to predict the frequency and dimensions of visible plumes from the project's proposed unabated cooling tower using the SACTI model. Many of the input parameters used by the Applicant do not appear to be correct per the guidelines provided in the SACTI User's Manual (Argonne National Lab., April 1984). Due to these apparent inconsistencies, the Applicant's SACTI results are not presented as part of this analysis.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 10% of seasonal (November through April) daylight no rain/fog (SDNRNF) high visual contrast hours is used to determine potential plume impact significance. The high visual contrast hours analysis methodology is provided below:

The Energy Commission has identified a "clear" sky category during which plumes have the greatest potential to cause adverse visual impacts. For this project the meteorological data set[2] used in the analysis categorizes total sky cover as "clear", "scattered", "broken", "overcast", "partially obscured", and obscured". When the opaque sky cover is less than 50% the ceiling height is given as unlimited, which is represented by the number "722". For the purpose of estimating the high visual contrast hours staff has included in the "Clear" category a) all hours with total sky cover defined as "clear" plus b) half of the non-obscured hours with unlimited ceiling height (i.e. hours with a sky opacity equal to or less than 50%). The rationale for including these two components in this category is as follows: a) plumes typically contrast most with sky under clear conditions and b) for a substantial portion of the time when total sky cover is not clear or obscured the opacity of the sky cover is relatively low (equal to or less than 50%), and these clouds do not substantially reduce contrast with plumes. Staff has estimated that approximately half of the hours with a sky opacity of less than 50% can be considered high visual contrast hours and are included in the "clear" sky definition.

If it is determined that the seasonal (November through April) daylight no rain/fog high visual contrast hour plume frequency is greater than 10% then plume dimensions are determined and a significance analysis of the plumes is included in the Visual Resources section of the Staff Assessment.

[2] This analysis uses TD3280 formatted hourly surface data.

CLOUD COVER DATA ANALYSIS

The results of the high visual contrast hours analysis is provided in **Table 3**.

Table 3
- Cooling Tower High Visual Contrast SDNRNF Plumes
CSVP Modeling Results – Limited Duct Firing Case

Amount of Total Sky Cover					
All		Clear		Scattered/Broken/Overcast	
Hrs	%	Hrs	%	Hrs	%
740	12.4	342	5.7	398	6.6

* Percentiles calculated by dividing the number of plume hours by the reference number of seasonal daylight no rain/fog hours (5,989).

For the Limited Duct Firing case, considered a reasonable worst-case for plume formation because it assumes duct firing for all ambient conditions above 50°F, the high visual contrast hours plume frequency is 5.7% of seasonal daylight no rain/fog hours. This is below the 10% threshold that would trigger a plume dimension modeling analysis and a visual impact analysis in the Visual Resources section of the Staff Assessment.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff evaluated the applicant's AFC (BEP II 2002a, AFC Sections 7.5.2.2.2 and 7.7.4.3) and Data Response #99 (BEP II 2002b) and performed an independent psychrometric analysis and dispersion modeling analysis. The Combustion Stack Visible Plume (CSVP) model was used to estimate the worst-case potential plume frequency, and provide data on predicted plume length, width, and height for each HRSG stack.

HRSG DESIGN PARAMETERS

Based on the stack exhaust parameters anticipated by the applicant for each HRSG stack, the frequency and size of visual plumes can be estimated. The operating data for these stacks are provided in **Table 4**.

Table 4 –
HRSG Exhaust Parameters

Parameter	**HRSG Exhaust Parameters**					
Stack Height	39.62 meters (130 feet)					
Stack Diameter	5.64 meters (18.5 feet)					
	Case 1		**Case 2**		**Case 3**	
Ambient Temp	20°F		59°F		95°F	
Ambient Relative Humidity	60%		60%		60%	
Duct Burner Status	On	Off	On	Off	On	Off
Exhaust Temperature	---	200°F	200°F	200°F	200°F	200°F
Exit Velocity	Calculated for each hour modeled					
Exhaust mass flow rate, lb/hr		3,768,897	3,562,120	3,557,661	3,298,242	3,293,783
Exhaust Molecular Weight	28.35 lbs/lb-mol (with duct firing) and 28.4 lbs/lb-mol (no duct firing)					
Moisture Content (% by vol.)	---	7.69%	8.40%	7.99%	9.78%	9.34%

Source: AFC (BEP II 2002a) Table 7.7-8, Appendix 7.7-A "Emission Calculation Spreadsheets", and Data Response, Set #1 (BEP II 2002b), DR #99.
Notes:
(1) For CSVP modeling, values were extrapolated or interpolated between data points as necessary.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff modeled the HRSG plumes using the CSVP model with a three-year meteorological data set, obtained from the National Climatic Data Center, for Blythe Airport. **Table 5** provides the CSVP model visible plume frequency results for each HRSG operating without duct firing.

Table 5 – Staff Predicted Hours with HRSG Steam Plumes
Blythe Airport 1989-1991 Meteorological Data

HRSG - No Duct Firing	Available (hr)	Plume (hr)	Percent
All Hours	26,280	58	0.22%
Daylight Hours	13,425	4	0.03%
Nighttime Hours	12,855	54	0.42%
Daylight No Rain/Fog Hours	13,265	3	0.02%
Seasonal Daylight No Rain/Fog Hours*	5,989	3	0.05%

*Seasonal conditions occur anytime from November through April.

Per the Applicant's discussion regarding the operating assumptions for the HRSGs, the duct burners will not be operational at ambient temperatures less than 50°F due to steam turbine flow limitations (BEP II 2002b, DR #100). For the proposed HRSGs operating with duct firing at temperatures of 50°F or greater, no visible steam plumes were predicted to occur.

The results provided in **Table 5** confirm that the visible plume formation would mainly occur during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. For the proposed HRSG operating without duct firing, the maximum temperature where a visible plume is predicted is 42°F when the relative humidity is 100%.

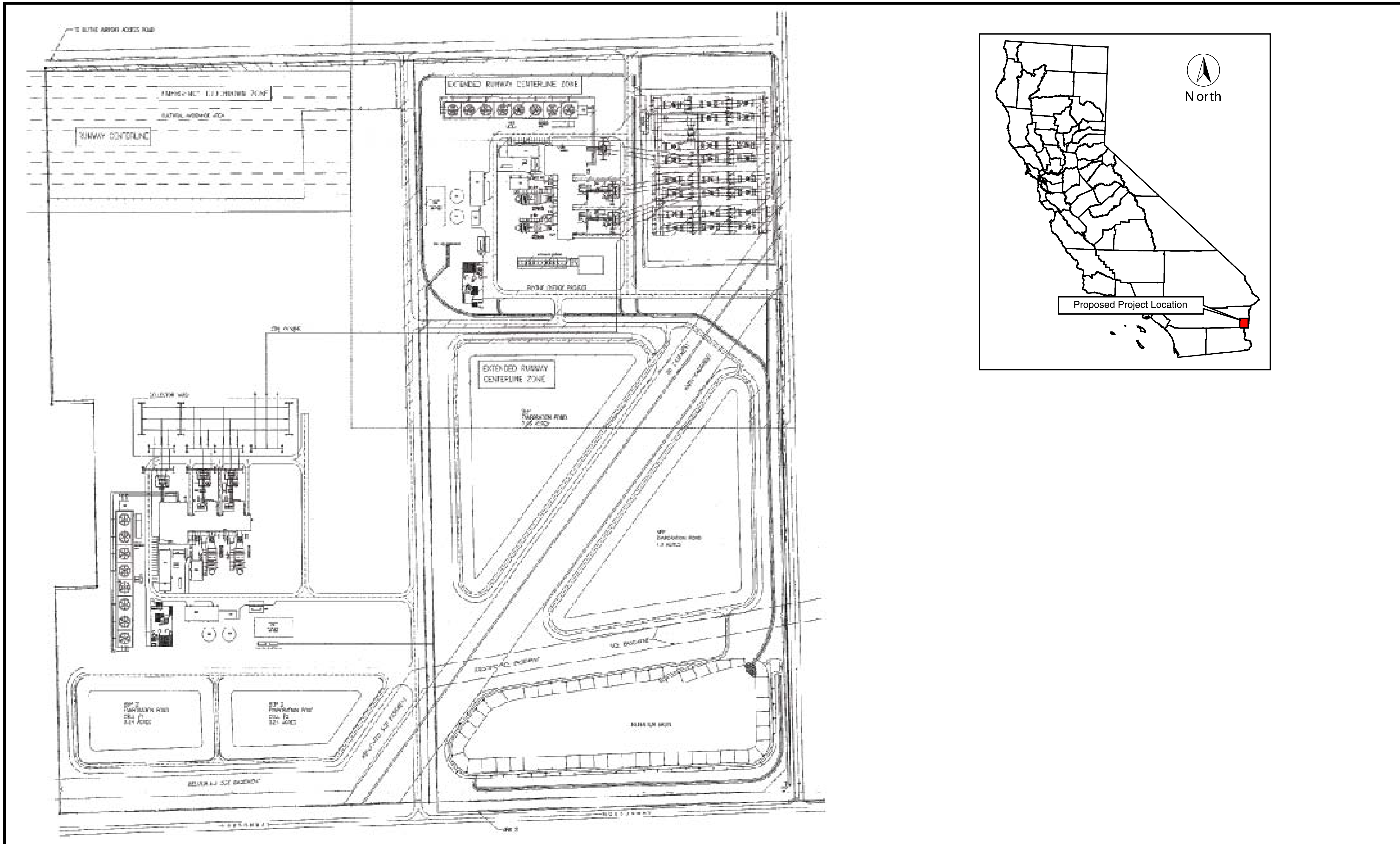
A plume frequency of 10% of seasonal (November through April) daylight no rain/fog high contrast hours is used as an initial plume impact study threshold trigger. The CSVP model predicts plume frequencies significantly less than 10% of seasonal daylight no rain/fog hours, which would not trigger additional study of the visual impacts of the plumes from the HRSGs.

REFERENCES

BEP II (Caithness Blythe II, LLC) 2002a. Application for Certification, Volumes 1 and 2 (02-AFC-1). Submitted to the California Energy Commission on February 19, 2002.

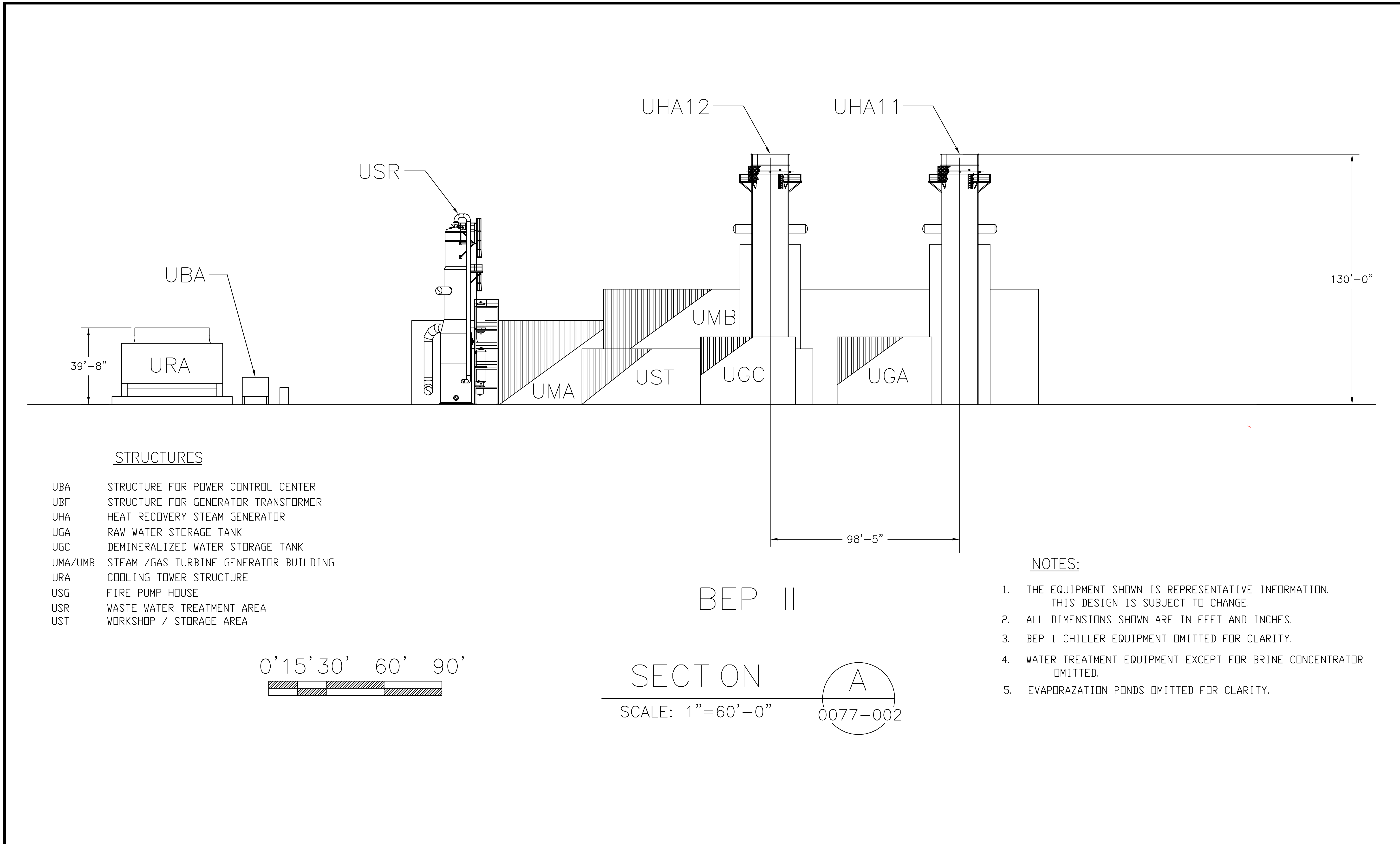
BEP II (Caithness Blythe II, LLC) 2002b. Data Response, Set #1. Submitted to the California Energy Commission. Docketed on September 30, 2002.

VISUAL RESOURCES - FIGURE 1
Blythe Energy Project Phase II - Site Layout



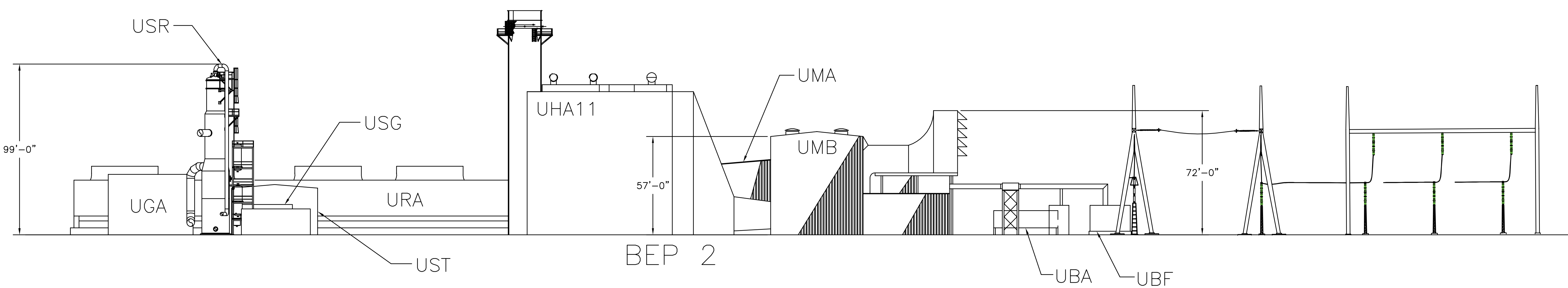
CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2002f, Figure 36-1

VISUAL RESOURCES - FIGURE 2
Blythe Energy Project Phase II - South Elevation View



SOURCE: BEP II 2002a, Figure 7.5-10c

VISUAL RESOURCES - FIGURE 3
Blythe Energy Project Phase II - East Elevation View



STRUCTURES

UBA	STRUCTURE FOR POWER CONTROL CENTER
UBF	STRUCTURE FOR GENERATOR TRANSFORMER
UHA	HEAT RECOVERY STEAM GENERATOR
UGA	RAW WATER STORAGE TANK
UGC	DEMINERALIZED WATER STORAGE TANK
UMA/UMB	STEAM /GAS TURBINE GENERATOR BUILDING
URA	COOLING TOWER STRUCTURE
USG	FIRE PUMP HOUSE
USR	WASTE WATER TREATMENT AREA
UST	WORKSHOP / STORAGE AREA
USA	INLET CHILLER EQUIPMENT

BEP II

SECTION C
SCALE: 1"=60'-0" 0077-002

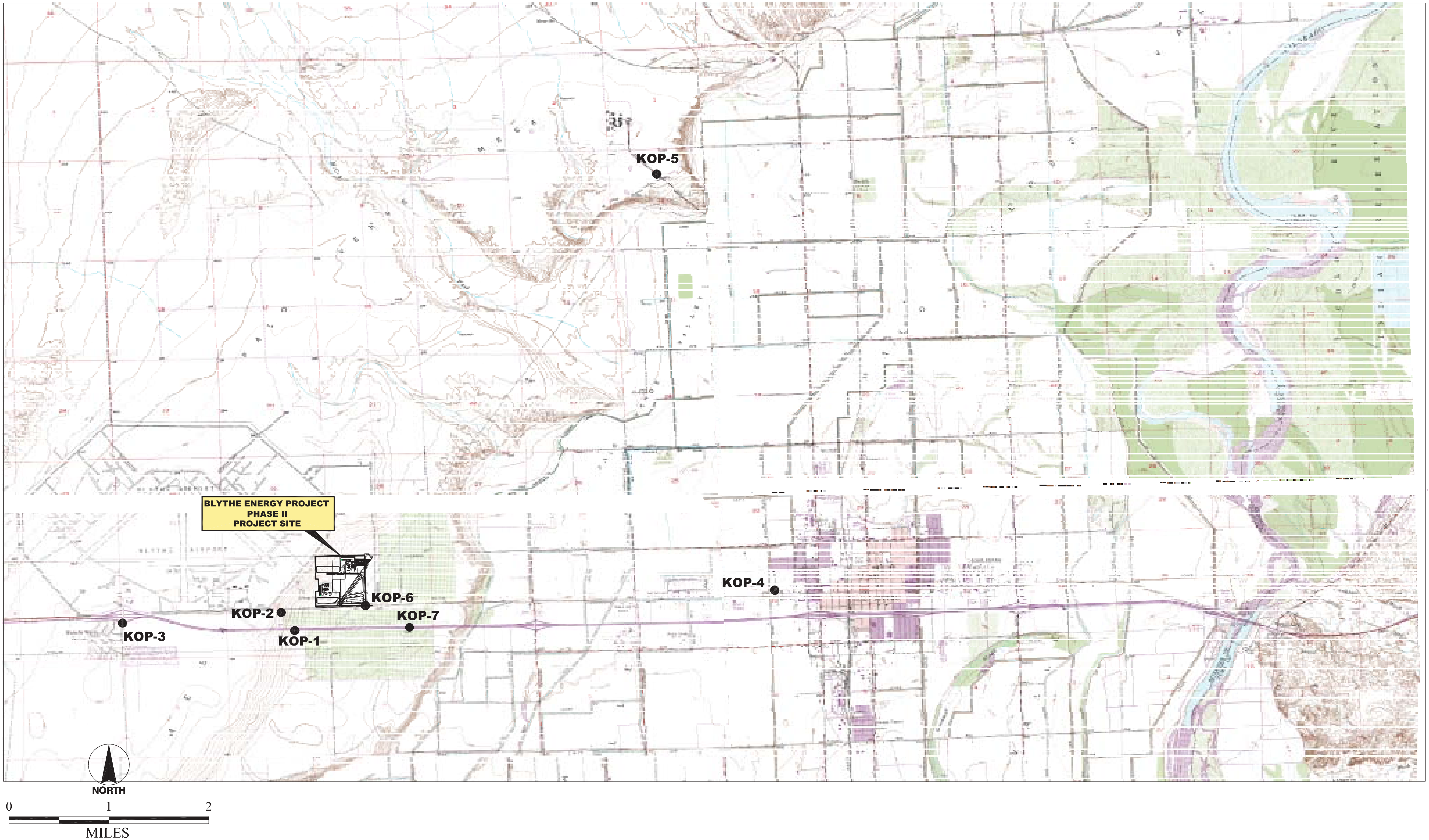
0'15'30' 60' 90'

NOTES:

1. THE EQUIPMENT SHOWN IS REPRESENTATIVE INFORMATION. THIS DESIGN IS SUBJECT TO CHANGE.
2. ALL DIMENSIONS SHOWN ARE IN FEET AND INCHES.
3. WATER TREATMENT EQUIPMENT EXCEPT FOR BRINE CONCENTRATOR OMITTED.
4. EVAPORAZATION PONDS OMITTED FOR CLARITY.

SOURCE: BEP II 2002a, Figure 7.5-10b

VISUAL RESOURCES - FIGURE 4
Blythe Energy Project Phase II - Location of Key Observation Points



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2002a, Figure 7.5-1

VISUAL RESOURCES - FIGURE 5A
Blythe Energy Project Phase II - KOP 1 - Existing View

EXISTING CONDITION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-1a

VISUAL RESOURCES - FIGURE 5B
Blythe Energy Project Phase II - KOP 1 - Photosimulation

PHOTO SIMULATION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-1b

VISUAL RESOURCES - FIGURE 6A

Blythe Energy Project Phase II - KOP 2 - Existing View

EXISTING CONDITION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: BEP II 2003a, Figure 223-2a

VISUAL RESOURCES - FIGURE 6B
Blythe Energy Project Phase II - KOP 2 - Photosimulation

PHOTO SIMULATION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-2b

VISUAL RESOURCES - FIGURE 7A
Blythe Energy Project Phase II - KOP 3 - Existing View

EXISTING CONDITION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-3a

VISUAL RESOURCES - FIGURE 7B
Blythe Energy Project Phase II - KOP 3 - Photsimulation

PHOTO SIMULATION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-3b

VISUAL RESOURCES - FIGURE 8A
Blythe Energy Project Phase II - KOP 4 - Existing View

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2002a, Figure 7.5-5a

VISUAL RESOURCES - FIGURE 8B
Blythe Energy Project Phase II - KOP 4 - Photosimulation

SOURCE: BEP II 2002a, Figure 7.5-5b

VISUAL RESOURCES - FIGURE 9A
Blythe Energy Project Phase II - KOP 5 - Existing View

EXISTING VIEW

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2002a, Figure 7.5-6a

VISUAL RESOURCES - FIGURE 9B
Blythe Energy Project Phase II - KOP 5 - Photosimulation

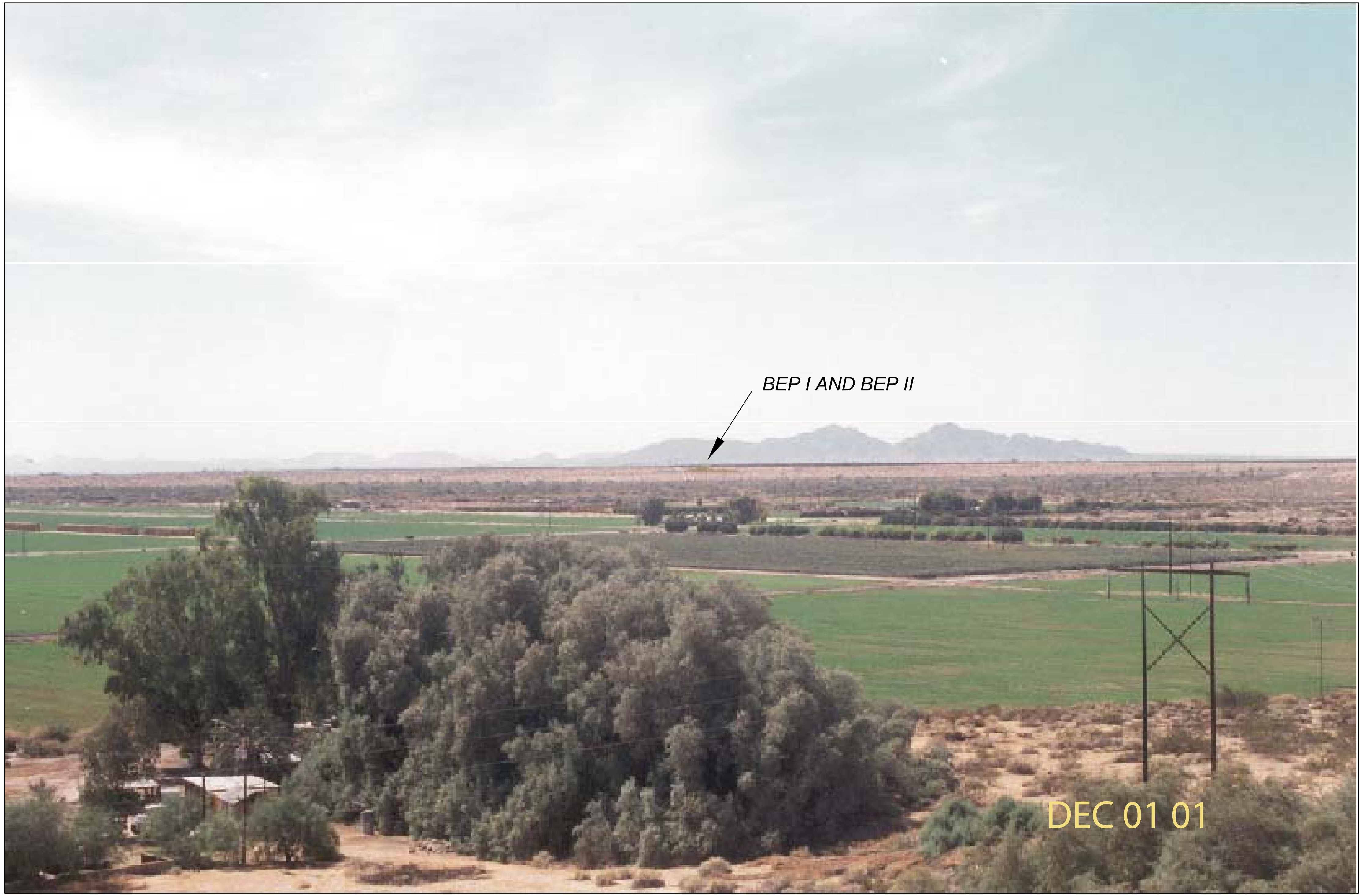
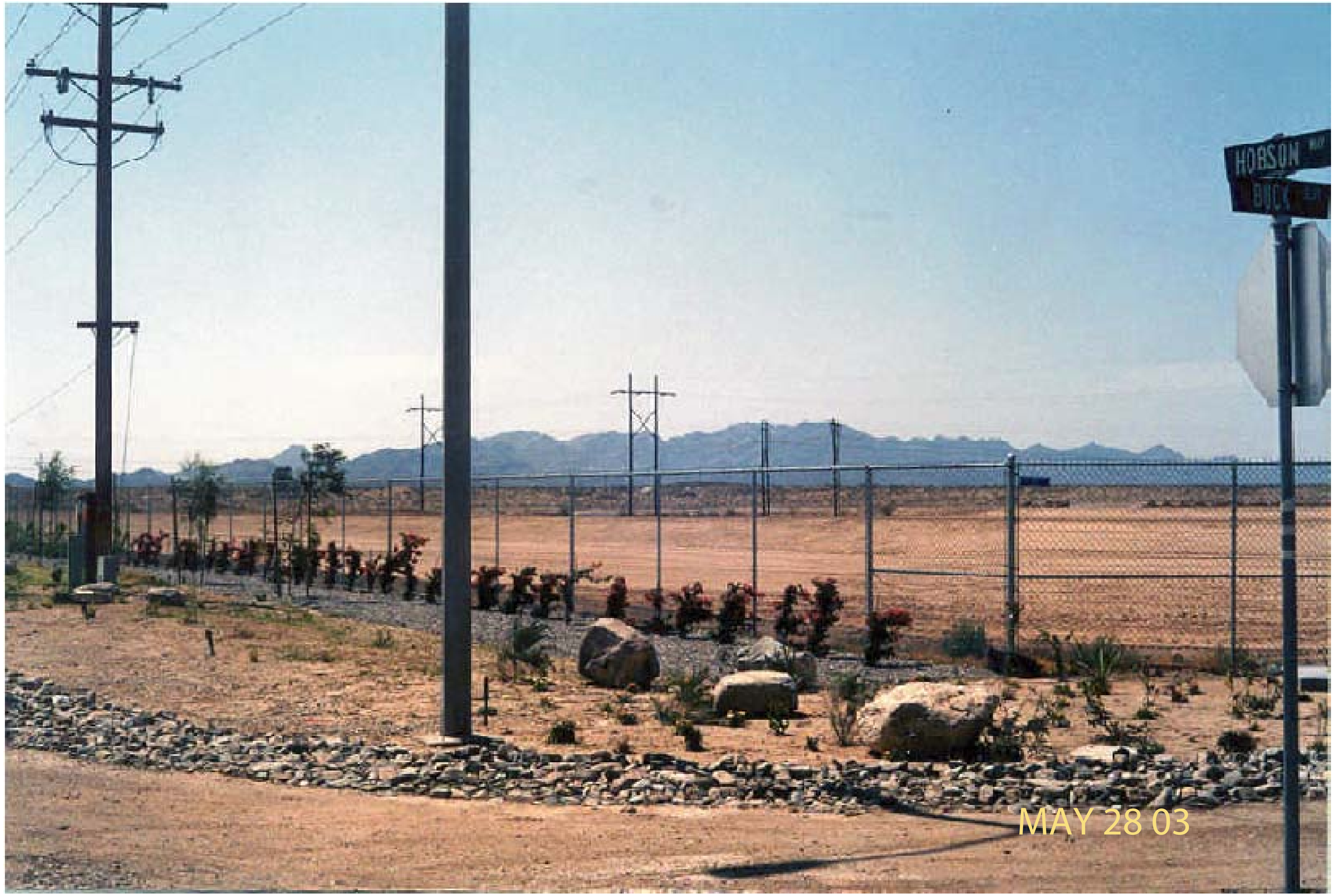


PHOTO SIMULATION

SOURCE: BEP II 2002a, Figure 7.5-6b

VISUAL RESOURCES - FIGURE 10A
Blythe Energy Project Phase II - KOP 6 - Existing View



EXISTING CONDITION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-4a

VISUAL RESOURCES - FIGURE 10B
Blythe Energy Project Phase II - KOP 6 - Photosimulation

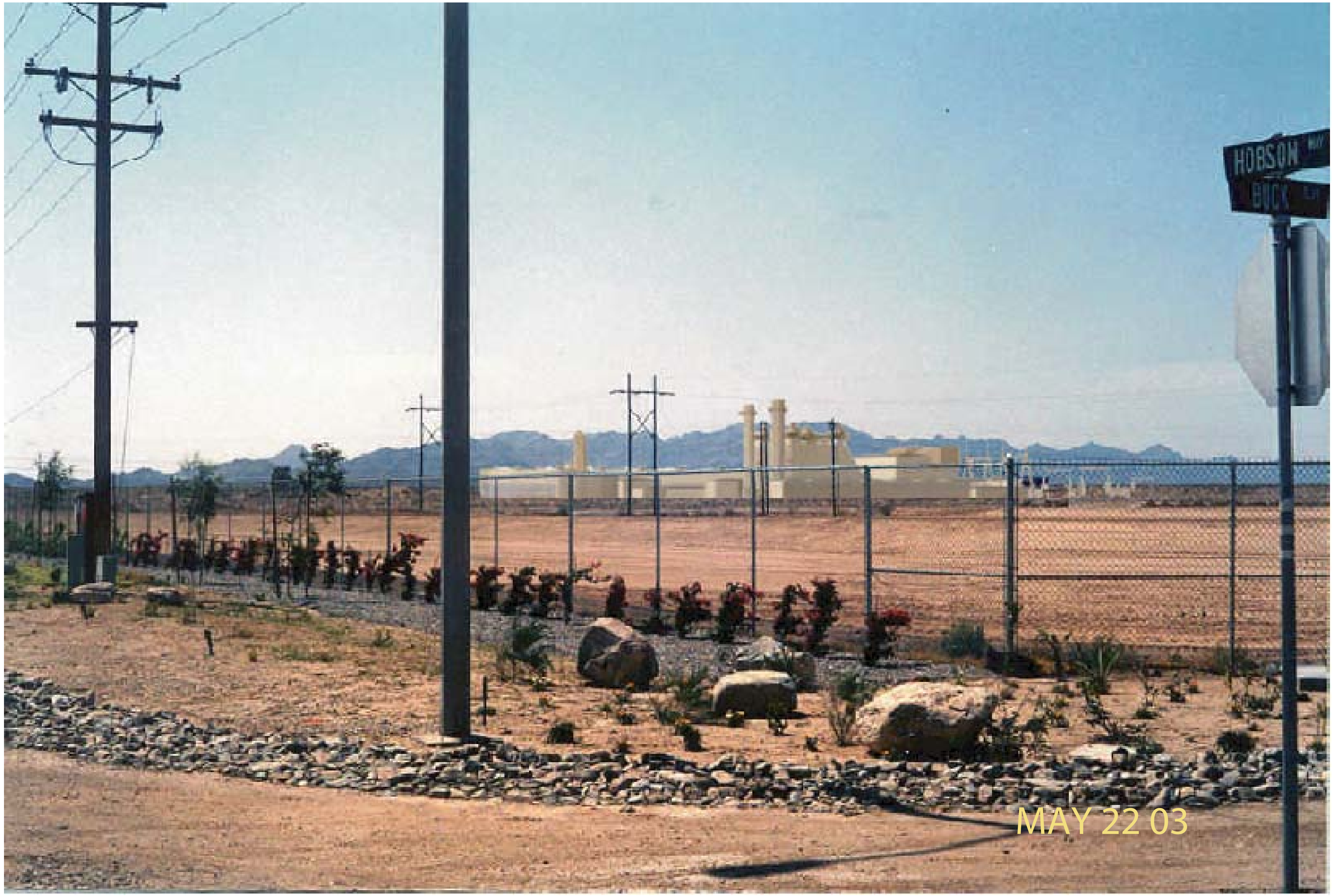


PHOTO SIMULATION

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: BEP II 2003a, Figure 223-4b

VISUAL RESOURCES - FIGURE 11
Blythe Energy Project Phase II - KOP 7 - Existing View

SOURCE: CEC Staff

WASTE MANAGEMENT

Ramesh Sundareswaran

INTRODUCTION

This analysis is to assess the potential impacts associated with the planning and managing of wastes generated from constructing and operating the proposed Blythe Energy Project Phase II (BEP II). It evaluates the proposed waste management plans and mitigation measures designed to reduce the risks and environmental impacts associated with handling, storing, and disposing of project-related hazardous and nonhazardous wastes. The technical scope of this analysis encompasses wastes generated during facility construction and operation, except project wastewaters, such as those discharged to evaporation ponds. Wastewater management is discussed in the **Soil and Water Resources** section of this document.

Energy Commission staff's objectives in its waste management analysis are to ensure that the management of the wastes will be in compliance with all applicable laws, ordinances, regulations, and standards (LORS). Compliance with LORS ensures that wastes generated during constructing and operating the proposed project will be managed in an environmentally safe manner; and disposal of project wastes will not result in significant adverse impacts to existing waste disposal facilities.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

A framework, based on environmental laws, ordinances, regulations and standards (LORS) exists to reduce detrimental risks to the public and environment from the generation, storage and disposal of both hazardous and nonhazardous wastes. The institutional and legal conditions of several laws, regulations, policies and programs that would regulate wastes from BEP II are outlined below.

FEDERAL

Resource Conservation and Recovery Act (42 U.S.C. § 6922)

The Resource Conservation and Recovery Act (RCRA) establishes requirements for the management of hazardous wastes from the time of generation to the point of ultimate treatment or disposal. RCRA requires generators of hazardous waste to comply with requirements regarding record keeping practices which identify quantities of hazardous wastes generated and their disposition, labeling practices and use of appropriate containers, use of a manifest system for transportation, and submission of periodic reports to the Environmental Protection Agency(EPA) or authorized state.

Title 40, Code of Federal Regulations, part 260

These sections contain regulations promulgated by the EPA to implement the requirements of RCRA as described above. Characteristics of hazardous waste are described in terms of ignitability, corrosivity, reactivity, and toxicity, and specific types of wastes are listed.

STATE

California Health and Safety Code §25100 et seq. (Hazardous Waste Control Act of 1972, as amended).

This act creates the framework under which hazardous wastes must be managed in California. It mandates the State Department of Health Services (now the Department of Toxic Substances Control (DTSC) under the California Environmental Protection Agency, or Cal EPA) to develop and publish a list of hazardous and extremely hazardous wastes, and to develop and adopt criteria and guidelines for the identification of such wastes. It also requires hazardous waste generators to file notification statements with Cal EPA and creates a manifest system to be used when transporting such wastes.

Title 14, California Code of Regulations, §17200 et seq. (Minimum Standards for Solid Waste Handling and Disposal)

These regulations set forth minimum standards for solid waste handling and disposal, guidelines to ensure conformance of solid waste facilities with county solid waste management plans, as well as enforcement and administration provisions.

Title 22, California Code of Regulations, §66262.10 et seq. (Generator Standards)

These sections establish requirements for generators of hazardous waste. Under these sections, waste generators must determine if their wastes are hazardous according to either specified characteristics or lists of wastes. As in the federal program, hazardous waste generators must obtain EPA identification numbers, prepare manifests before transporting the waste off-site, and use only permitted treatment, storage, and disposal facilities. Additionally, hazardous waste must only be handled by registered hazardous waste transporters. Generator requirements for record keeping, reporting, packaging, and labeling are also established.

SETTING

PROJECT AND SITE DESCRIPTION

The proposed project is a nominal 520 megawatt natural gas fired combined cycle generating facility consisting of two gas turbine generators with associated heat recovery steam generators and one steam turbine generator (BEP II 2002d). The proposed location is on unimproved desert land, about five miles west of the city of Blythe. The site is in Riverside County, but was annexed by the City of Blythe in 2000.

A Phase I Environmental Site Assessment (ESA) was performed by Greystone Environmental Consultants in June 2001 to document actual or potential environmental concerns at the BEP II site based on past and present uses of the site (BEP II 2002d). It was performed in accordance with the guidelines of the American Society for Testing and Materials standard 1527 for Phase I ESAs. The Phase I ESA involved gathering of information from historical records, aerial photographs, government and other sources, and a physical tour of the site with recordation of visual, olfactory and tactile perceptions. It was also supplemented with some limited soil sampling due to concerns regarding possible contamination in an area located on the northern boundary of the site. The Phase I ESA concluded the following:

- There is no evidence of any existing, past or threatened releases of contamination in connection with surrounding offsite properties that can impact the site.
- There is a former World War II era landfill located along the northern boundary of the site. Soil sampling along the northern boundary indicated an elevated level of lead at 570 parts per million (ppm) at one sampling location.

The concentration, however, is well below the U.S. Environmental Protection Agency, Region IX, Preliminary Remediation Goal (PRG) of 750 ppm for lead in soil permitted for industrial use (US EPA 2002). PRGs are chemical concentrations that correspond to fixed levels of health risk in soil, water, and air and serve as tools that can be used for evaluating and cleaning up contaminated sites. No additional sampling or remediation is therefore warranted at the site, as no adverse health effects are associated with the presence of lead.

IMPACTS

PROJECT SPECIFIC IMPACTS

Construction

Site preparation, along with construction of the generating plant and associated facilities, will generate a variety of nonhazardous and hazardous wastes.

Nonhazardous waste streams from construction may include packing paper, cardboard, wood, glass, and plastics. These will be generated from packing materials, waste construction lumber, insulation materials, and empty containers. BEP II estimates that about 90 tons of these wastes will be generated during construction (BEP II 2002d). These wastes will be recycled where practical, with the rest discharged to the Blythe Sanitary Landfill (BEP II 2002d). Hazardous material containers may be classified as nonhazardous if they are emptied and managed according to specified methods (Cal. Code Regs., tit. 22, §66261.7).

An estimated 50 tons of waste asphalt or concrete will be generated during construction of foundations, parking lots, and roads (BEP II 2002d). Uncontaminated soil and concrete may be used for fill material either on or offsite, with the remainder being disposed of in the Blythe Sanitary Landfill.

Up to 25 tons of metal wastes from welding and cutting operations, packing materials, trim, and empty containers and drums will be generated (BEP II 2002d). This also includes aluminum and copper electrical wiring waste from the power plant, substation, and transmission lines. These wastes will be recycled through scrap metal brokers with the remainder disposed to the Blythe landfill.

Hazardous wastes that may be generated during construction include waste oil and grease, paint, spent solvent, welding materials, and cleanup materials from spills of hazardous substances. These are typically generated in minor amounts. The construction contractor is considered the actual waste generator and will be responsible for proper hazardous waste handling. Such wastes will be collected in hazardous waste accumulation containers near the point of generation. The containers will be taken to the construction contractor's hazardous waste storage area and within 90 days will be delivered to an authorized hazardous waste management facility (BEP II 2002d).

Although the Phase I ESA did not identify onsite environmental concerns that may not currently be apparent, subsurface contamination could be potentially encountered during earth moving activities. Depending on the nature and extent of contamination present, additional hazardous wastes may require transportation off-site to a permitted facility.

Operation

Under normal operating conditions, the proposed facility will generate both nonhazardous and hazardous wastes.

Nonhazardous wastes generated during plant operation include trash, office wastes, empty containers, broken or used parts, used packing material, and used filters. It is estimated that about 65 cubic yards annually of such wastes will be generated (BEP II 2002d). Metal parts and other materials such as paper, aluminum, and plastic will be recycled through brokers, when possible. Nonrecyclable solid wastes will be transported to the Blythe Sanitary Landfill.

Routine project operation will generate a variety of hazardous wastes. AFC Table 7.11-1 summarizes the hazardous wastes that are anticipated to be routinely generated, along with estimated amounts and planned management methods (BEP II 2002d). Also, residuals with potentially high concentrations of heavy metals and mineral solids, will be generated from the evaporation pond used for storing process wastewater. Much of the hazardous waste generated is suitable for recycling. Used turbine lubricating oil will be collected for recycling by a licensed waste oil recycler (BEP II 2002d). Every three to four years, air pollution control catalysts must be replaced in order to maintain their control efficiency. Spent catalyst will be returned to the manufacturer for metals reclamation or disposal. Liquid hazardous wastes consisting of solvents containing hazardous levels of heavy metals will be generated during pre-operational and periodic flushing and cleaning of pipes and the heat recovery steam generators (HRSG). A contractor will be used for such cleaning operations and will transport liquid wastes to an offsite facility licensed to manage such wastes. Residuals from the evaporation pond will be discharged to an offsite disposal facility.

IMPACT ON EXISTING WASTE DISPOSAL FACILITIES

The Blythe Sanitary Landfill is a permitted class III (nonhazardous) facility about seven miles north of Blythe. It is projected to remain operational until 2073 and accepts an average daily load of about 50 tons/day. The volume of nonhazardous waste expected from constructing and operating BEP II is expected to be a fraction of one percent of the Blythe landfill's annual capacity. The total remaining capacity of the landfill is estimated to be five million cubic yards. Even discounting the effects of recycling on the total amount of non-hazardous wastes destined for landfilling, the amounts of waste generated during project construction and operation are insignificant relative to existing disposal capacity.

Three Class I landfills in California, at Kettleman Hills in King's County, Buttonwillow in Kern County, and Westmoreland in Imperial County, are permitted to accept hazardous waste. In total, there is in excess of twenty million cubic yards of remaining hazardous waste disposal capacity at these landfills, with remaining operating lifetimes of over 50 years. The amount of hazardous waste transported to these landfills has decreased in recent years due to source reduction efforts by generators, and the transport of waste out of state that is hazardous under California law, but not federal law.

Much of the hazardous waste generated during facility construction and operation will be recycled, such as used oil and spent catalysts. Even without recycling, the generation of hazardous waste from BEP II would be a very small fraction (less than one percent) of existing capacity and will not significantly impact the capacity or remaining life of any of the state's Class I landfills.

CUMULATIVE IMPACTS

Due to the minor amounts of wastes generated during project construction and operation, the insignificant impacts on individual disposal facilities, and the availability of additional regional landfills in Riverside County, cumulative impacts will be insignificant for both hazardous and nonhazardous wastes.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is more than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this PSA). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

Based on the **Waste Management** analysis, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project and, therefore, there are no waste-related environmental justice issues related to this project.

FACILITY CLOSURE

During any type of facility closure (see staff's General Conditions section which discusses planned, unexpected temporary, and unexpected permanent closure), one concern is that project wastes not pose any potentially significant problem to the public, workers, or the environment. Staff believes that conditions of certification in the General Conditions section will adequately address waste management issues related to closure.

In the case of unexpected temporary closure, waste management practices normally required by LORS and already in-place (such as limiting hazardous waste accumulation time to 90 days and requiring proper containment) would likely be adequate to avoid significant problems. In addition, staff's General Conditions for Facility Closure require preparation of an on-site contingency plan which shall provide for removal of hazardous wastes and draining of all chemicals from storage tanks and other equipment for temporary closures exceeding 90 days.

An approved on-site contingency plan is also required to protect public health and safety in the case of unexpected permanent closure. The plan must provide for the removal of hazardous materials and hazardous wastes, draining of all chemicals from storage tanks and other equipment, and the safe shutdown of all equipment.

For planned permanent closure, BEP II will develop a facility closure plan prior to commencement of closure which will detail compliance with LORS applicable at the time of closure (BEP II 2002d). The decommissioning plan will attempt to maximize the recycling of all facility components. Chemicals will be drained from all equipment, and all wastes will be collected and disposed of in accordance with applicable LORS.

COMPLIANCE WITH APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Energy Commission staff concludes that BEP II will be able to comply with all applicable LORS regulating the management of hazardous and non-hazardous wastes during facility construction and operation. The applicant is required to dispose of hazardous and non-hazardous wastes at facilities approved by the Regional Water Quality Control Board or the Cal EPA - Department of Toxic Substances Control. Because hazardous wastes will be produced during project construction and operation, BEP II must acquire and maintain an EPA identification number as a hazardous waste generator. Accordingly, BEP II will be required to properly store, package and label waste, use only approved transporters, prepare hazardous waste manifests, and keep detailed records. Pursuant to title 22, California Code of Regulations, section 67100.1 et seq., a hazardous waste source reduction and management review may be required, depending on the amounts of hazardous waste ultimately generated.

MITIGATION

BEP II intends to implement the following safeguards and measures during construction and operation of the proposed project:

- A hazardous waste reduction program will be developed to minimize the quantity of hazardous wastes generated. Management methods will include source reduction, recycling, treatment, and selection of less toxic materials.
- Nonhazardous wastes will be recycled whenever practical.

Staff has examined the waste management related measures proposed by BEP II and concludes that, together with applicable LORS and the additional conditions proposed by staff, such measures will adequately assure that no significant environmental impacts will result from the management and disposal of project-related waste.

CONCLUSIONS AND RECOMMENDATIONS

Management of the wastes generated during construction and operation of BEP II will not result in any significant adverse impacts if the waste management measures and safeguards proposed in the Application for Certification (02-AFC-1) and the proposed conditions of certification are implemented.

CONDITIONS OF CERTIFICATION

WASTE-1 The project owner shall provide the resume of a Registered Professional Engineer or Geologist, who shall be available for consultation during soil excavation and grading activities, to the CPM for review and approval. The resume shall show experience in remedial investigation and feasibility studies.

The Registered Professional Engineer or Geologist shall be given full authority by the project owner to oversee any earth moving activities that have the potential to disturb contaminated soil.

Verification: At least 30 days prior to the start of site mobilization, the project owner shall submit the resume to the CPM for approval.

WASTE-2 If potentially contaminated soil is unearthed during excavation at the proposed site as evidenced by discoloration, odor, or other signs, the Registered Engineer or Geologist shall inspect the site, determine the need for sampling to confirm the nature and extent of contamination, and file a written report to the project owner and CPM stating the recommended course of action, prior to any further construction activity at that location.

Depending on the nature and extent of contamination, the Registered Engineer or Geologist shall have the authority to temporarily suspend construction activity at the location for the protection of workers or the general public. If, in the opinion of the Registered Engineer or Geologist, significant remediation may be required, the project owner shall contact representatives of the Riverside County Hazardous Materials Department, Colorado River Basin Regional Water Quality Control Board and the Cypress regional office of the California Department of Toxic Substances Control for guidance and possible oversight.

Verification: The project owner shall submit any reports filed by the Registered Engineer or Geologist to the CPM within 5 days of their receipt. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.

WASTE-3 The project owner shall obtain a hazardous waste generator identification number from the Department of Toxic Substances Control prior to generating any hazardous waste.

Verification: The project owner shall keep its copy of the identification number on file at the project site and notify the CPM via the Monthly Compliance Report of its receipt.

WASTE-4 Upon becoming aware of any impending waste management-related enforcement action by any local, state, or federal authority, the project owner shall notify the CPM of any such action taken or proposed to be taken against the project itself, or against any waste hauler or disposal facility or treatment operator with which the owner contracts.

Verification: The project owner shall notify the CPM in writing within 10 days of becoming aware of an impending enforcement action. The CPM shall notify the project owner of any changes that will be required in the manner in which project-related wastes are managed.

WASTE-5 The project owner shall prepare a Construction Waste Management Plan and an Operation Waste Management Plan for all wastes generated during construction and operation of the facility, respectively, and shall submit both plans to the CPM for review and approval. The plans shall contain, at a minimum, the following:

∉ A description of all waste streams, including projections of frequency, amounts generated and hazard classifications; and

∉ Methods of managing each waste, including treatment methods and companies contracted with for treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/reduction plans.

Verification: No less than 30 days prior to the start of site mobilization, the project owner shall submit the Construction Waste Management Plan to the CPM.

The operation waste management plan shall be submitted to the CPM no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions within 20 days of notification by the CPM.

In the Annual Compliance Reports, the project owner shall document the actual waste management methods used during the year compared to the planned management methods.

REFERENCES

BEP II (Blythe Energy Project Phase II.)2002d Revised Application for Certification for Blythe II. 07/03/2002 (tn:26100)

US EPA 2002 US Environmental Protection Agency. URL: http/www/epa.gov/region09/waste/sfund/prg/index.html

WORKER SAFETY AND FIRE PROTECTION

Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

Worker safety and fire protection is regulated through laws, ordinances, regulations, and standards (LORS), at the federal, State, and local levels. Industrial workers at the facility operate equipment and handle hazardous materials daily and may face hazards that can result in accidents and serious injury. Protection measures are employed to eliminate these hazards or to minimize the risk through special training, protective equipment and procedural controls.

The purpose of this Staff Assessment is to assess the worker safety and fire protection measures proposed by the Blythe Energy Project Phase II (BEP II) and to determine whether the applicant has proposed adequate measures to:

∉ comply with applicable safety LORS;

∉ protect the workers during construction and operation of the facility;

∉ protect against fire; and

∉ provide adequate emergency response procedures.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

In 1970 Congress enacted Public Law 91-596, the Federal Occupational Safety and Health Act of 1970. This Act mandates safety requirements in the workplace and is found in Title 29 of the United States Code, sections 651 through 678. Implementing regulations are codified at Title 29 of the Code of Federal Regulations, under General Industry Standards sections 1910.1 to 1910.1500 which clearly define the procedures for promulgating regulations and conducting inspections to implement and enforce safety and health procedures to protect workers, particularly in the industrial sector. Most of the general industry safety and health standards now in force under this act represent a compilation of existing federal standards and national consensus standards. These include standards from the voluntary membership organizations of the American National Standards Institute (ANSI) and the National Fire Protection Association (NFPA), which publishes the National Fire Codes.

The purpose of the Occupational Safety and Health Act is to “assure so far as possible every working man and woman in the nation safe and healthful working conditions and to preserve our human resources” (29 USC § 651). The Federal Department of Labor promulgates and enforces safety and health standards that are applicable to all businesses affecting interstate commerce. The Department of Labor established the Occupational Safety and Health Administration (OSHA) in 1971 to implement the responsibilities assigned by this act.

Applicable Federal requirements include:

- 29 U.S. Code section 651 et seq. (Occupational Safety and Health Act of 1970);
- 29 CFR sections 1910.1 to 1910.1500 (Occupational Safety and Health Administration Safety and Health Regulations);
- 29 CFR sections 1952.170 to 1952.175 (Federal approval of California's plan for enforcement of its own Safety and Health requirements, in lieu of most of the Federal requirements found in 29 CFR §1910.1 to 1910.1500).

STATE

California passed the Occupational Safety and Health Act of 1973 ("Cal/OSHA") as published in the California Labor Code section 6300. Regulations promulgated as a result of the Act are codified at Title 8 of the California Code of Regulations, beginning with sections 337 to 560 and continuing with sections 1514 through 8568. The California Labor Code requires that the Cal/OSHA Standards Board adopt standards at least as effective as the federal standards (Labor Code § 142.3(a)) and thus all Cal/OSHA health and safety standards meet or exceed the Federal requirements. Hence, California obtained federal approval of its State health and safety regulations, in lieu of the federal requirements. The Federal Secretary of Labor, however, continually oversees California's program and will enforce any federal standard for which the State has not adopted a Cal/OSHA counterpart.

The State of California Department of Industrial Relations is charged with responsibility for administering Cal/OSHA. Employers are responsible for informing their employees about workplace hazards, potential exposure and the work environment (Labor Code § 6408). Cal/OSHA's principal tool in ensuring that workers and the public are informed is the Hazard Communication standard first adopted in 1981 (8 CCR §5194). This regulation was promulgated in response to California's Hazardous Substances Information and Training Act of 1980. It was later revised to mirror the Federal Hazard Communication Standard (29 CFR §1910.1200), which established on the federal level an employee's "right to know" about chemical hazards in the workplace, and added the provision of applicability to public sector employers. A major component of this regulation is the required provision of Material Safety Data Sheets (MSDSs) to workers. MSDSs provide information on the identity, toxicity, and precautions to take when using or handling hazardous materials in the workplace.

Finally, 8 CCR section 3203 requires that employers establish and maintain a written Injury and Illness Prevention Program to identify workplace hazards and communicate them to its employees through a formal employee-training program.

Applicable State requirements include:

- 8 CCR section 339 - List of hazardous chemicals relating to the Hazardous Substance Information and Training Act;
- 8 CCR section 337, et seq. - Cal/OSHA regulations;
- 8 CCR section 3221 – Fire Prevention Plans

- 24 CCR section 3, et seq. - incorporates the current addition of the Uniform Building Code;
- Health and Safety Code section 25500, et seq. - Risk Management Plan requirements for threshold quantity of listed acutely hazardous materials at the facility; and
- Health and Safety Code sections 25500 to 25541 - Hazardous Material Business Plan detailing emergency response plans for hazardous materials emergency at the facility.

LOCAL

The California Building Standards Code, published at Title 24 of the California Code of Regulations section 3, et seq., is comprised of eleven parts containing the building design and construction requirements relating to fire and life safety and structural safety. The California Building Standards Code incorporates current editions of the Uniform Building Code and includes the electrical, mechanical, energy, and fire codes applicable to the project. The City of Blythe Building and Safety department enforces the 2001 edition of the California Building Standards Code.

NFPA standards are incorporated into the California Uniform Fire Code (Cal. Code Regs., tit. 24, part 9). The fire code contains general provisions for fire safety, including: 1) required road and building access; 2) water supplies; 3) installation of fire protection and life safety systems; 4) fire-resistive construction; 5) general fire safety precautions; 6) storage of combustible materials; 7) exits and emergency escapes; and 8) fire alarm systems.

Similarly, the Uniform Fire Code (UFC) Standards contain standards of the American Society for Testing and Materials and the NFPA. It is the United State's premier model fire code. It is updated annually as a supplement and published every third year by the International Fire Code Institute to include all approved code changes in a new edition. The California Fire Code, a companion publication to the UFC, incorporates current editions of the UFC standards. The City of Blythe adopted the 2001 edition of the California Fire Code (CFC) and is the administering agency for the CFC standards.

Applicable local (or locally enforced) requirements include:

- 1998 Edition of California Fire Code and all applicable NFPA standards (24 CCR Part 9);
- California Building Code Title 24, California Code of Regulations (24 CCR § 3, et seq.); and
- Uniform Fire Code, 1997.

SETTING

The proposed project would be located within the City of Blythe approximately five miles west of the center of the City.

BEP II would be a nominally rated 520 MW combined-cycle power plant, proposed as an addition to the approved Blythe Energy Project Phase I (BEP I), and would be located adjacent to the BEP I site boundary. BEP II would require no off-site linear facilities and would interconnect on-site with existing BEP transmission and natural gas pipelines.

Fire support services to the site will be under the jurisdiction of the City of Blythe Fire Department (BFD). The BFD is located at 201 North Commercial Street approximately 5 miles away with a response time of 10 to 15 minutes (HRC 2000 and BFD 2003). The BFD has 30 trained volunteer firefighters, one full time fire marshal, and four fire engines (BEP II 2002d Page 7.6-7). The BFD has a mutual aid agreement with the Riverside County Fire Department (RCFD), which has two stations that are closer to the project site and would be the actual first responders. Fire Station No. 45 is the closest station to the site and is located at 17280 Hobsonway, approximately 0.75 miles west of the project site. The response time to the project site is estimated to be 3-5 minutes, and this station has two engines with two full-time trained firefighters. By the end of year 2003, the RCFD will upgrade the permanent staff at station 45 from 2 to 3 firefighters per shift. All staff at station 45 are trained Emergency Medical Technicians (EMTs) (RCFD 2003a and 2003b). RCFD station 43 is located at 140 West Barnard Street, approximately 5 miles from the project site with an estimated response time of 7 to 10 minutes (HRC 2000 and RCFD 2003a). This station has two engines, two full-time trained firefighters, and up to 15 volunteers available during emergencies (BEP II 2002d Page 7.6-7). RCFD station 44 is located in the town of Ripley, approximately 9 miles from the project site with an estimated response time of 15 minutes (HRC 2000). Staff determined that the response times of RCFD and BFD are adequate and consistent with the UFC and the NFPA. This information is summarized in Table 1, below.

A Fire Service Needs Assessment was prepared in 2000 for BEP I, and concluded that funding was required from that applicant to improve staffing, training and equipment in order to reduce impacts on the fire and emergency services to insignificance. The BEP II applicant has stated that a Fire Service Needs Assessment for BEP Phase II would be prepared after certification if needed to reach an agreement with the City of Blythe Fire Department and the Riverside County Fire Department on additional funding that might be necessary to reduce impacts from BEP II to insignificance. In conversations with the fire departments, both BFD and RCFD indicated that they are not concerned with the timing of the needs assessment but think it is necessary to conduct one before reaching an agreement with the applicant on mitigation needed to reduce any impacts on their departments (BFD 2003 and RCFD 2003b). Both the BFD and the RCFD indicated that some additional equipment may be necessary to deal with the specific needs of a power plant in order to mitigate the impacts on their fire department (RCFD 2003a, RCFD 2003b, and BFD 2003).

Because of the location and the volunteer nature of the Blythe Fire Department, mitigation was necessary to reduce the impacts of BEP I on the local fire response and emergency services. The applicant has provided the BFD with $575,000 for equipment and training (Blythe 2002 and HRC 2000). Staff had assumed that the mitigation for BEP I would be available and sufficient for response to the BEP II site as well. Staff finds the chances that both facilities would experience a fire or other emergency at the same time (cumulative impact) is remote. However, both the BFD and the RCFD indicated that some additional equipment may be necessary. Staff has contacted both departments several times to obtain more information on the specific needs of the fire departments, but has not received a specific response by the date of this PSA. In December 2002 the City of Blythe indicated it was preparing a needs assessment for BEP II (Blythe 2002). This needs assessment was to have been provided to staff in May 2003 as per statements made by the applicant. However, on July 27, 2003, staff received notice from the applicant that the needs assessment would not be competed and submitted to the CEC until after certification (Cameron 2003). Without the needs assessment, and without specific information from the fire departments on their expected needs, staff cannot make a determination about impacts on the fire and emergency services. Thus, without this information, staff cannot make any conclusions about the presence or absence of significant impacts on fire protection services.

WORKER SAFETY AND FIRE PROTECTION Table 1
Equipment and Personnel at BFD and RCFD

Equipment and Personnel at BFD and RCFD Station	Response Time	Distance to BEP II	Equipment	Number of Firefighters
Station No. 45 Hobsonway Blythe, CA (Riverside County Fire Department)	Approx. 3 to 5 minutes	Approx. 0.75 miles	2 – Type 1 Engine 1 – Type 4, Squad Vehicle	3 trained firefighters by 2004 15 to 20 volunteer firefighters
Station No. 43 140 West Barnard St. Blythe, CA (Riverside County Fire Department)	Approx. 5 to 7 minutes	Approx. 5 miles	2 – Type 1 Engine 1 – Water Tender 1 – Type 4, Squad Vehicle	2 trained firefighters 15 to 20 volunteer firefighters
Blythe Fire Department 201 North Commercial St. Blythe, CA (City of Blythe Fire Department)	Approx.10 to 15 minutes	Approx. 5 miles	1 – 50 foot ladder truck 4 – Fire Truck 1 – Squad Vehicle 1 – Quick Response Vehicle	33 trained volunteer firefighters 1 Fire Marshal

The BFD fire station is considered first responder for HazMat incidents, with backup service provided by the RCFD stations 43 and 45. Currently, the BFD fire station and RCFD stations 43 and 45 do not have any trained hazmat technicians. Additional response would be provided by the Riverside County HazMat Response Team located in Beaumont, approximately two hours away and manned with 4 Hazmat technicians (BEP II 2002d Page 7.6-8, HRC 2000, and RCFD 2003b). The needs assessment conducted for BEP I indicated that this may not result in timely response as the expected hazardous materials event may last less than 1 hour. Therefore, the needs assessment for BEP I concluded: “the power plant must build-in all feasible mitigations to reduce the hazardous materials threat, and must provide for the response of trained, private hazardous materials clean-up companies from Los Angeles or Phoenix, to clean up hazardous waste after a release (HRC 2000).” According to Tony CDeBaca from the City of Blythe, the mitigation measure chosen by the applicant was to train all personnel at BEP I to the level of Hazmat Technicians, who are capable of complete hazmat response including extraction. He suggested that BEP II should either pay the BFD and RCFD for training to bring their staff up to the level of Hazmat Technicians, or train their own staff as they did at BEP I (BFD 2003). Staff proposes an additional Condition of Certification (**WORKER SAFETY-3**) that would require the applicant to train BEP II personnel to the level of Hazmat Technicians as in the original BEP in order to reduce the response time to an adequate one and reduce the potential impacts from a HazMat incident to insignificant.

IMPACTS

WORKER SAFETY

Industrial environments are potentially dangerous during construction and operation of facilities. Workers at the proposed project will be exposed to loud noises, moving equipment, trenches, and confined space entry and egress problems. The workers may experience falls, trips, burns, lacerations, and numerous other injuries. They have the potential to be exposed to falling equipment or structures, chemical spills, hazardous waste, fires, explosions, and electrical sparks and electrocution. It is important for the BEP II to have well-defined policies and procedures, training, and hazard recognition and control at their facility to minimize such hazards and protect workers. If the facility complies with all LORS, workers will be adequately protected from health and safety hazards.

BEP II is also proposing to use a wet cooling system using water from the raw water storage system. The raw water will be obtained from on-site wells and therefore no off-site pipelines will be constructed. One additional new well will be added by BEP II with similar characteristics to the two existing BEP I wells that are 600 and 620 feet deep. Compliance with worker safety regulations would protect workers from any hazards associated with the construction and operation of the cooling system and wells. This cooling option would not result in a significant impact to worker safety and health. Additionally, this cooling system will not represent a significant hazard and will not significantly impact fire protection services.

FIRE HAZARDS

During construction and operation of the proposed BEP II there is the potential for both small fires and major structural fires. Electrical sparks, combustion of fuel oil, natural gas, hydraulic fluid, mineral oil, insulating fluid at the power plant switchyard or flammable liquids, explosions, and over-heated equipment, may cause small fires. Major structural fires in areas without automatic fire detection and suppression systems are unlikely to develop at power plants. Fires and explosions of natural gas or other flammable gasses or liquids are rare. Compliance with all LORS will be adequate to assure protection from all fire hazards.

APPLICANT'S PROPOSED MITIGATION

WORKER SAFETY

A Safety and Health Program will be prepared by the applicant to minimize worker hazards during construction and operation. Staff uses the phrase "Safety and Health Program" to refer to the measures that will be taken to ensure compliance with the applicable LORS during the construction and operational phases of the project.

Construction Safety and Health Program

The BEP II encompasses construction and operation of a natural gas fired facility. Workers will be exposed to hazards typical of construction and operation of a gas-fired combined cycle facility.

Construction Safety Orders are published at 8 CCR section 1502, et seq. These requirements are promulgated by Cal/OSHA and are applicable to the construction phase of the project. The Construction Safety and Health Program will include the following:

- Construction Injury and Illness Prevention Program (8 CCR § 1509)
- Construction Fire Protection and Prevention Plan (8 CCR § 1920)
- Personal Protective Equipment Program (8 CCR §§ 1514 - 1522)
- Emergency Action Program and Plan

Additional programs under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will include:

- Electrical Safety Program
- Motor Vehicle and Heavy Equipment Safety Program;
- Forklift Operation Program;
- Excavation/Trenching Program;
- Fall Prevention Program;
- Scaffolding/Ladder Safety Program;
- Articulating Boom Platforms Program;
- Crane and Material Handling Program;
- Housekeeping and Material Handling and Storage Program;
- Respiratory Protection Program;
- Employee Exposure Monitoring Program;
- Hand and Portable Power Tool Safety Program;
- Hearing Conservation Program;
- Back Injury Prevention Program;

- Hazard Communication Program;
- Heat and Cold Stress Monitoring and Control Program; and
- Pressure Vessel and Pipeline Safety Program.

The AFC includes adequate outlines of each of the above programs (BEP II 2002d, Section 7.10.2.1). Prior to the start of construction of the BEP II, detailed programs and plans will be provided pursuant to the Condition of Certification **WORKER SAFETY-1**.

Operations and Maintenance Safety and Health Program

Prior to the start of operations at the BEP II, the Operations and Maintenance Safety and Health Program will be prepared. This operational safety program will include the following programs and plans:

- Injury and Illness Prevention Program (8 CCR § 3203);
- Emergency Action Plan (8 CCR § 3220);
- Hazardous Materials Management Program;
- Fire Protection and Prevention Program (8 CCR § 3221); and
- Personal Protective Equipment Program (8 CCR §§ 3401 to 3411).

In addition, the requirements under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will be applicable to the project. Written safety programs for the BEP II, which the applicant will develop, will ensure compliance with the above-mentioned requirements.

The AFC includes adequate outlines of the Injury and Illness Prevention Program, Emergency Action Plan, Fire Protection and Prevention Program, and Personal Protective Equipment Program (BEP II 2002d, Section 7.10.2.2). Prior to operation of the BEP II, all detailed programs and plans will be provided pursuant to Condition of Certification **WORKER SAFETY-2**.

Safety and Health Program Elements

The applicant provided the proposed outlines for both a Construction Safety and Health Program and an Operation Safety and Health Program. The measures in these plans are derived from applicable sections of state and federal law. The major items required in both Safety and Health Programs are as follows:

Injury and Illness Prevention Program (IIPP)

The Applicant will submit expanded Construction and Operations Illness and Injury Prevention Programs to Cal/OSHA for review and comment 30 days prior to construction and operation of the project, respectively.

The IIPP will include the following components as presented in the AFC (BEP II 2002d Section 7.10.2.2.1):

- identity of person(s) with authority and responsibility for implementing the program;
- establish safety and health policy of the plan;
- define work rules and safe work practices for construction activities;
- system for ensuring that employees comply with safe and healthy work practices;
- system for facilitating employer-employee communications;
- procedures for identifying and evaluating workplace hazards and developing necessary program(s);
- methods for correcting unhealthy/unsafe conditions in a timely manner;
- determine and establish training and instruction requirements and programs; and
- specify safety procedures.

Emergency Action Plan

California regulations require an Emergency Action Plan (8 CCR § 3220). The AFC contains a satisfactory outline for an emergency action plan (BEP II 2002d Section 7.10.2.2.3).

The outline lists the following features:

- establish emergency escape procedures and emergency escape route for the facility;
- determine procedures to be followed by employees who remain to operate critical plant operations before they evacuate;
- provide procedures to account for all employees and visitors after emergency evacuation of the plant has been completed;
- specify rescue and medical duties for assigned employees;
- identify fire and emergency reporting procedures to regulatory agencies;
- develop alarm and communication system for the facility;
- establish a list of personnel to contact for information on the plan contents;
- provide emergency response procedures for ammonia, natural gas releases, or other hazardous chemicals that could exceed plant boundaries;
- develop a Spill Prevention Control and Countermeasure (SPCC) Plan; and
- determine and establish training and instruction requirements and programs.

Fire Prevention Plan

California Code of Regulations requires an Operations Fire Prevention Plan (8 CCR § 3221). The AFC describes a proposed Fire Protection and Prevention Plan which is acceptable to staff (BEP II 2002d Section 7.10.2.2.2). The plan will include the following topics:

- determine general program requirements;
- develop good housekeeping practices and procedures;
- establish employee alarm and/or communication system(s);
- provide portable fire extinguishers at appropriate site locations;
- locate fixed fire fighting equipment in suitable areas;
- specify fire control requirements and procedures;
- establish proper flammable and combustible liquid storage facilities;
- identify the location and use of flammable and combustible liquids;
- provide proper dispensing facilities for flammable materials;
- determine proper disposal requirements for flammable liquids;
- identify proper servicing and refueling locations; and
- establish and determine training and instruction requirements and programs.

Staff proposes that the applicant submit a final Fire Protection and Prevention Plan to the California Energy Commission Compliance Project Manager (CPM) for review and approval and to the City of Blythe Fire Department for review and comment to satisfy proposed Conditions of Certification **WORKER SAFETY-1** and **WORKER SAFETY-2**.

Staff has found, however, that the potential for both work-related and non-work related heart attacks exists at power plants. In fact, staff's research on the frequency of EMS response to gas-fired power plants shows that the majority of the responses for cardiac emergencies involved non-work related incidences including visitors. The need for prompt response within a few minutes is well documented in the medical literature. Staff finds that the quickest medical intervention can only be achieved with the use of an on-site cardio-converter; the response from an off-site provider would take longer regardless of the provider location and could be too late to convert a cardiac arrhythmia to normal sinus rhythm. This fact is also well documented and serves as the basis for many private and public locations (e.g., airports, factories, government buildings) maintaining on-site cardiac defibrillation devices. The CEC maintains such a device at its building in Sacramento. Staff thus finds that with the advent of modern cost-effective cardiac defibrillation devices, it is proper in a power plant environment to maintain such a device on-site in order to convert cardiac arrhythmias resulting from industrial accidents or other non-work related causes (Cummins 1987, Marenco 2001). Therefore, an additional Condition of Certification (**WORKER SAFETY-4**) is proposed which would require that a portable automatic cardiac defibrillator be located on site.

Personal Protective Equipment Program

California regulations require Personal Protective Equipment (PPE) and first aid supplies whenever hazards are present that, due to process, environment, chemicals or mechanical irritants, can cause injury or impair bodily function as a result of absorption, inhalation or physical contact (8 CCR section 3380 to 3400). The BEP II operational environment will require PPE.

All safety equipment must meet National Institute of Safety and Health (NIOSH) or ANSI standards and will carry markings, numbers, or certificates of approval. Respirators must meet NIOSH and Cal/OSHA standards. Each employee must be provided with the following information pertaining to the protective clothing and equipment:

- proper use, maintenance, and storage;
- when the protective clothing and equipment are to be used;
- benefits and limitations; and
- when and how the protective clothing and equipment are to be replaced.

The PPE Program ensures that employers comply with the applicable requirements for PPE and provides employees with the information and training necessary to protect them from potential workplace hazards.

Written Safety Program

In addition to the specific plans listed above, additional LORS apply to the project, called "safe work practices." Both the Construction and the Operations Safety Programs will address safe work practices under a variety of programs. The components of these programs include the following:

- Fall Protection Program;
- Hot Work Safety Program;
- Confined Space Entry Program;
- Hearing Conservation Program;
- Hazard Communication Program;
- Process Safety Management (PSM) Program; and
- Contractor Safety Program.

Safety Training Programs

Employees will be trained in the safe work practices described in the above-referenced safety programs.

FIRE PROTECTION

Staff reviewed the information provided in the AFC to determine if available fire protection services and equipment would adequately protect workers, and to determine the project's impact on fire protection services in the area (BEP II 2002d, Section 7.10.2.2.2). The project will rely on both onsite fire protection systems and local fire protection services. The onsite fire protection system provides the first line of defense for small fires. In the event of a major fire, fire support services, including trained firefighters and equipment for a sustained response, would be provided by the City of Blythe Fire Department and Riverside County Fire Department.

During construction portable fire extinguishers will be provided in accordance with Cal-OSHA requirements at locations including portable office spaces, welding and braising areas, flammable chemical storage areas, and mobile equipment. A 4,000 gallon water pumping truck will be located on-site until the permanent fire pump system is operational (BEP II 2002d Page 7.10-7).

The information in the AFC indicates that the project intends to meet the fire protection and suppression requirements of the California Fire Code, all applicable recommended NFPA standards (including Standard 850 addressing fire protection at electric generating plants), and all Cal-OSHA requirements. Elements include both fixed and portable fire extinguishing systems. The BEP II fire protection system will be interconnected to the existing BEP fire protection system. The fire water will be supplied from the raw water storage tank constructed as part of the BEP I project, with a minimum supply of 300,000 gallons dedicated for fire suppression purposes. The raw water storage tank has a holding capacity of 600,000 gallons, and make-up water will be provided by two on-site wells and pumps capable of restoring water at a total maximum rate of 6,000 gallons/minute (BEP II 2002d, Page 2-17 and BEP II 2003b, DR-187). A verbal response at the Data Response workshop held on April 23 indicated that the water rights issue seems to be resolved and therefore the applicant will have the right to use groundwater for fire protection. Please refer to the **Soil & Water Resources** section of this Staff Assessment for further discussion of water rights. With this issue resolved, the use of groundwater will ensure an adequate supply of water for fire protection needs.

The firewater pumping system consists of an electric motor-driven fire pump, an emergency backup driven by a diesel engine, and an electric jockey pump to maintain the pressure in the main fire loop. The fire loop pumps have a maximum capacity each of 2500 gallons/minute to deliver water to the fire protection water piping network. The two electric well pumps at BEP I have a maximum capacity of 3000 gallons/minute each. Staff finds that this system will provide more than an adequate quantity of fire-fighting water to facility fire hydrants, and automatic fire suppression (sprinkler/deluge) systems.

A deluge type fire protection system will be provided for the combustion turbine generator.

Fire hydrants and portable fire extinguishers will be located throughout the power plant site at appropriate intervals according to code. The fire plant loop will also supply a vapor suppression system at the aqueous ammonia storage tank area.

In addition to the fixed fire protection system, smoke detectors, flame detectors, temperature detectors, and appropriate class of service portable extinguishers will be located throughout the facility at code-approved intervals. These systems are standard requirement by the NFPA and the UFC and staff finds that they will ensure adequate fire protection.

The applicant will be required to provide the final Fire Protection and Prevention Program to staff and to both the City of Blythe Fire Department and Riverside County Fire Department, prior to construction and operation of the project, to confirm the adequacy of the proposed fire protection measures.

CUMULATIVE IMPACTS

Staff reviewed the potential for the construction and operation of BEP II, combined with existing industrial facilities, and expected new facilities, to result in impacts on the fire and emergency service capabilities of the City of Blythe Fire Department and Riverside County Fire Department. Staff found that without a Fire Services Needs Assessment, and without specific information from the fire departments on their expected needs, staff can not make a determination at this time weather cumulative impacts on the fire and emergency services would be significant or not.

In conversations with the BFD and the RCFD, both departments stated that they wish to conduct a Fire Service Needs Assessment in order to assess the adequacy of their staff and equipment in dealing with incidents at both BEP I and the proposed BEP II (BFD 2003, RCFD 2003b). The applicant has stated that a Fire Service Needs Assessment would be prepared, if necessary, after certification before reaching an agreement with the fire departments on necessary funding, staffing and training to be provided by the applicant in order to reduce impacts on the fire departments.

Because of the remote location and the volunteer nature of the Blythe Fire Department, mitigation was necessary to reduce impacts of BEP I on local fire response and emergency services. The BEP I applicant has provided the BFD with $575,000 for equipment and training (Blythe 2002 and HRC 2000). Staff assumes that the BEP I mitigation would also be available for an emergency response to the BEP II site. Staff finds the chances that both facilities would experience a fire or other emergency at the same time (cumulative impact) is remote.

This needs assessment for BEP II was to have been provided to staff in May 2003 as per statements made by the applicant. However, on July 27, 2003, staff received notice from the applicant that the needs assessment would not be competed and submitted to the CEC until after certification (Cameron 2003). Without the needs assessment, and without specific information from the fire departments on their expected needs, staff cannot make a determination about impacts of BEP II on the fire and emergency services, or on cumulative impacts. Thus, staff cannot make any conclusions about the presence or absence of significant cumulative impacts on fire protection services.

FACILITY CLOSURE

The project owner/operator is responsible for maintaining an operational fire protection system during closure activities. The project must also maintain compliance with all applicable health and safety LORS during that time. A facility closure plan will be developed prior to closure to incorporate these requirements.

CONCLUSION AND RECOMMENDATIONS

If the Applicant for the proposed BEP II provides a Project Construction Safety and Health Program and a Project Operations and Maintenance Safety and Health Program, as required by Conditions of Certification **WORKER SAFETY -1** and **-2**, staff believes that the project will incorporate sufficient measures to ensure adequate levels of industrial safety, and comply with applicable LORS. Staff also concludes that if the applicant trains the BEP II staff to the level of Hazmat Technicians (Condition of Certification **WORKER SAFETY –3**), BEP II staff would be able to respond quickly and adequately to hazardous materials incidents. Staff therefore finds that with **WORKER SAFETY-3** and with the applicant's proposed mitigation regarding hazardous materials spills, the impacts of an on-site hazardous material spill would be reduced to an insignificant level. Staff also notes that with the advent of modern cost-effective cardiac defibrillation devices, it is proper in a power plant environment to maintain such a device on-site in order to convert cardiac arrhythmias resulting from industrial accidents or other non-work related causes (Cummins 1987, Marenco 2001). Therefore, an additional Condition of Certification (**WORKER SAFETY-4**) is proposed which would require that a portable automatic cardiac defibrillator be located on site.

If the Energy Commission certifies the project, staff recommends that the following proposed Conditions of Certification be adopted. The proposed Conditions of Certification provide assurance that the Construction Safety and Health Program and the Operations and Maintenance Safety and Health Program proposed by the applicant will be reviewed by the appropriate agencies before implementation. The conditions also require verification that the proposed plans adequately assure worker safety and fire protection and comply with applicable LORS.

In regards to off-site fire protection and emergency medical services, the applicant and the City of Blythe Fire Department have not provided staff with adequate relevant and specific information for staff to conduct a thorough analysis and make a determination regarding impacts to local services. In December 2002, the City of Blythe indicated it was preparing a needs assessment for BEP II (Blythe 2002). This needs assessment was to have been provided to staff in May 2003 as per statements made by the applicant. However, on July 27, 2003, staff received notice from the applicant that the needs assessment would not be competed and submitted to the CEC until after certification (Cameron 2003).

Without a Fire Services Needs Assessment for BEP II and without specific information from the fire departments on their expected needs, staff cannot make a determination at this time whether impacts on the fire and emergency services would be significant. Staff must have this information prior to issuing the FSA.

PROPOSED CONDITIONS OF CERTIFICATION

WORKER SAFETY-1 The project owner shall submit to the Compliance Project Manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

- A Construction Personal Protective Equipment Program;
- A Construction Exposure Monitoring Program;
- A Construction Injury and Illness Prevention Program;
- A Construction Emergency Action Plan; and

- A Construction Fire Protection and Prevention Plan.

The Personal Protective Equipment Program, the Exposure Monitoring Program, and the Injury and Illness Prevention Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable Safety Orders. The Construction Emergency Action Plan and the Fire Protection and Prevention Plan shall be submitted to the City of Blythe Fire Department and the Riverside County Fire Department for review and comment prior to submittal to the CPM for approval.

Verification: At least 30 days prior to the start of construction, the project owner shall submit to the CPM for review and approval a copy of the Project Construction Safety and Health Program. The project owner shall provide a letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that they have reviewed and commented on the Construction Fire Protection and Prevention Plan and Emergency Action Plan.

WORKER SAFETY-2 The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- An Operation Injury and Illness Prevention Plan;
- An Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire Protection and Prevention Program (8 CCR § 3221); and;
- Personal Protective Equipment Program (8 CCR §§ 3401-3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the Cal/OSHA Consultation Service, for review and comment concerning compliance of the program with all applicable Safety Orders. The Operation Fire Protection Plan and the Emergency Action Plan shall also be submitted to the City of Blythe Fire Department and the Riverside County Fire Department for review and comment.

Verification: At least 30 days prior to the start of operation, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety & Health Program. It shall incorporate Cal/OSHA Consultation Service's comments, if any, stating that they have reviewed and accepted the specified elements of the proposed Operations and Maintenance Safety and Health Plan. The project owner shall provide a letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that they have reviewed and commented on the Operations Fire Protection and Prevention Plan and the Emergency Action Plan.

WORKER SAFETY-3 Prior to the delivery of any hazardous materials to the project site, the project owner shall train the personnel at the BEP II facility to the level of Hazmat Technicians capable of responding to hazardous materials incidents.

<u>Verification:</u> At least thirty (30) days prior to the delivery of hazardous materials to the site, the project owner shall provide the CPM with a letter indicating the number of employees that have been trained as Hazmat Technicians.

WORKER SAFETY-4 The project owner shall provide a portable automatic cardiac defibrillator on site during construction and operation.

<u>Verification:</u> At least 30 days prior to the start of site mobilization the project owner shall submit to the CPM proof that a portable automatic cardiac defibrillator exists on site.

REFERENCES

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Engineering

Assessment

FACILITY DESIGN

Shahab Khoshmashrab, Al McCuen and Steve Baker

INTRODUCTION

Facility Design encompasses the civil, structural, mechanical and electrical engineering design of the project. The purpose of the Facility Design analysis is to:

- verify that the laws, ordinances, regulations and standards (LORS) applicable to the engineering design and construction of the project have been identified;
- verify that the project and ancillary facilities have been described in sufficient detail, including proposed design criteria and analysis methods, to provide reasonable assurance that the project can be designed and constructed in accordance with all applicable engineering LORS, and in a manner that assures public health and safety;
- determine whether special design features should be considered during final design to deal with conditions unique to the site which could influence public health and safety; and
- describe the design review and construction inspection process and establish Conditions of Certification that will be used to monitor and ensure compliance with the engineering LORS and any special design requirements.

FINDINGS REQUIRED

The Warren Alquist Act requires the Energy Commission to "prepare a written decision ….which includes…(a) Specific provisions relating to the manner in which the proposed facility is to be designed, sited and operated in order to protect environmental quality and assure public health and safety…[and] (d)(1) Findings regarding the conformity of the proposed site and related facilities…with public safety standards…and with other relevant local, regional, state and federal standards, ordinances, or laws…" (Pub. Resources Code, §25523).

SUBJECTS DISCUSSED

Subjects discussed in this analysis include:

- identification of the engineering LORS applicable to facility design;
- evaluation of the applicant's proposed design criteria, including the identification of those criteria that are essential to ensuring public health and safety;
- proposed modifications and additions to the Application for Certification (AFC) that are necessary to comply with applicable engineering LORS; and
- conditions of Certification proposed by staff to ensure that the project will be designed and constructed to assure public health and safety and comply with all applicable engineering LORS.

SETTING

Caithness Blythe II, LLC proposes to construct and operate a nominally rated 520 megawatt combined-cycle power plant known as the Blythe Energy Project Phase II (BEP II). The project will be located approximately five miles west of the City of Blythe, Riverside County. The site will occupy approximately 15 acres on a 76 acre site, and will lie in seismic zone 3. For more information on the site and related project description, please see the **Project Description** section of this document. References to "the City" and "the County" designate the City of Blythe and Riverside County, respectively. Additional engineering design details are contained in the Application for Certification (AFC), in Appendices 8A through 8E (BEP 2002b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Lists of LORS applicable to each engineering discipline (civil, structural, mechanical and electrical) are described in the AFC (BEP 2002b, Appendices 8A through 8E). Some of these LORS include the California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), and guidelines promulgated by the American National Standards Institute (ANSI), American Society of Mechanical Engineers (ASME), American Society for Testing and Materials (ASTM) and American Welding Society (AWS).

ANALYSIS

The basis of this analysis is the applicant's analysis and proposed construction methods and list of engineering LORS and design criteria set forth in the AFC.

SITE PREPARATION AND DEVELOPMENT

Staff has evaluated the proposed design criteria for grading, flood protection, erosion control, site drainage and site access. Staff has assessed the criteria for designing and constructing linear support facilities such as a natural gas pipeline and water pipelines. The applicant proposes to use accepted industry standards (see AFC Appendices 8A through 8E for a representative list of applicable industry standards), design practices and construction methods in preparing and developing the site. Staff concludes that the project, including its linear facilities, would most likely comply with all applicable site preparation LORS, and proposes Conditions of Certification (see below and the **Geology and Paleontology** section of this document) to ensure compliance.

MAJOR STRUCTURES, SYSTEMS AND EQUIPMENT

Major structures, systems and equipment are defined as those structures and associated components or equipment that are necessary for power production and are costly to repair or replace, that require a long lead time to repair or replace, or that are used for the storage, containment, or handling of hazardous or toxic materials, or may become potential health and safety hazards if not constructed according to the applicable engineering LORS. Major structures and equipment will be identified through compliance with proposed Condition of Certification **GEN-2** (below).

The AFC contains lists of the civil, structural, mechanical and electrical design criteria that demonstrate the likelihood of compliance with applicable engineering LORS, and that staff believes are essential to ensuring that the project is designed in a manner that protects public health and safety.

The project shall be designed and constructed to the 2001 edition of the California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and other applicable codes and standards in effect at the time design and construction of the project actually commences. In the event the initial designs are submitted to the Chief Building Official (CBO) for review and approval when the successor to the 2001 CBSC is in effect, the 2001 CBSC provisions, identified herein, shall be replaced with the applicable successor provisions.

Certain structures in a power plant may be required, under the CBC, to undergo dynamic lateral force (structural) analysis; others may be designed using the simpler static analysis procedure. In order to ensure that structures are analyzed using the appropriate lateral force procedure, staff has included Condition of Certification **STRUC-1** (below), which in part, requires review and approval by the CBO of the project owner's proposed lateral force procedures prior to the start of construction.

PROJECT QUALITY PROCEDURES

The AFC (BEP 2002b, § 8.1.5) states that a project Quality Program will be used on the project to ensure that systems and components will be designed, fabricated, stored, transported, installed and tested in accordance with the technical codes and standards appropriate for a power plant. Compliance with design requirements will be verified through an appropriate program of inspections and audits. Employment of this quality assurance/quality control (QA/QC) program would ensure that the project is actually designed, procured, fabricated, and installed as contemplated in this analysis.

COMPLIANCE MONITORING

Under Section 104.2 of the CBC, the CBO is authorized and directed to enforce all the provisions of the CBC. For all energy facilities certified by the Energy Commission, the Energy Commission is the CBO and has the responsibility to enforce the code. In addition, the Energy Commission has the power to render interpretations of the CBC and to adopt and enforce rules and supplemental regulations to clarify the application of the CBC's provisions.

The Energy Commission's design review and construction inspection process is developed to conform to CBC requirements and to ensure that all facility design Conditions of Certification are met. As provided by Section 104.2.2 of the CBC, the Energy Commission appoints experts to carry out the design review and construction inspections and act as delegate CBO on behalf of the Energy Commission. These delegates typically include the local building official and/or independent consultants hired to cover technical expertise not provided by the local official. The applicant, through permit fees as provided by CBC Sections 107.2 and 107.3, pays the costs of the reviews and inspections. While building permits in addition to the Energy Commission certification are not required for this project, in lieu permit fees are paid by the applicant consistent with CBC Section 107, to cover the costs of reviews and inspections.

Engineering and compliance staff will invite the local building authority, either the City or the County, or a third party engineering consultant, to act as CBO for the project. When an entity has been identified to perform the duties of CBO, Energy Commission staff will complete a Memorandum of Understanding (MOU) with that entity that outlines its roles and responsibilities and those of its subcontractors and delegates.

Staff has developed proposed Conditions of Certification to ensure public health and safety and compliance with engineering design LORS. Some of these conditions address the roles, responsibilities and qualifications of the applicant's engineers responsible for the design and construction of the project (proposed Conditions of Certification **GEN-1** through **GEN-8**). Engineers responsible for the design of the civil, structural, mechanical and electrical portions of the project are required to be registered in California, and to sign and stamp each submittal of design plans, calculations and specifications submitted to the CBO. These conditions require that no element of construction subject to CBO review and approval shall proceed without prior approval from the CBO. They also require that qualified special inspectors be assigned to perform or oversee special inspections required by the applicable LORS.

While the Energy Commission and delegate CBO have the authority to allow some flexibility in scheduling construction activities, these conditions are written to require that no element of construction of permanent facilities subject to CBO review and approval, that would be difficult to reverse or correct, may proceed without prior approval of plans by the CBO. Those elements of construction that are not difficult to reverse are allowed to proceed without approval of the plans. The applicant shall bear the responsibility to fully modify those elements of construction to comply with all design changes that result from the CBO's subsequent plan review and approval process.

FACILITY CLOSURE

The removal of a facility from service, or decommissioning, as a result of the project reaching the end of its useful life, may range from "mothballing" to removal of all equipment and appurtenant facilities and restoration of the site. Future conditions that may affect the decommissioning decision are largely unknown at this time.

In order to assure that decommissioning of the facility will be completed in a manner that is environmentally sound, safe and will protect public health and safety, the applicant shall submit a decommissioning plan to the Energy Commission for review and approval prior to the commencement of decommissioning. The plan shall include a discussion of:

- proposed decommissioning activities for the project and all appurtenant facilities constructed as part of the project;

- all applicable LORS, local/regional plans and the conformance of the proposed decommissioning activities to the applicable LORS and local/regional plans;
- the activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities; and
- decommissioning alternatives, other than complete site restoration.

The above requirements should serve as adequate protection, even in the unlikely event of project abandonment. Staff has proposed general conditions (see **General Conditions**) to ensure that these measures are included in the Facility Closure plan.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

1. The laws, ordinances, regulations and standards (LORS) identified in the AFC and supporting documents are those applicable to the project.

2. Staff has evaluated the proposed engineering LORS, design criteria and design methods in the record, and concludes that the design, construction and eventual closure of the project are likely to comply with applicable engineering LORS.

3. The Conditions of Certification proposed will ensure that the proposed facilities are designed and constructed in accordance with applicable engineering LORS. This will occur through the use of design review, plan checking and field inspections, which are to be performed by the CBO or other Energy Commission delegate. Staff will audit the CBO to ensure satisfactory performance.

4. Even though future conditions that may affect decommissioning are largely unknown at this time, it can reasonably be concluded that if the project owner submits a decommissioning plan as required in the **General Conditions** portion of this document prior to the commencement of decommissioning, the decommissioning procedure is likely to occur in compliance with all applicable engineering LORS.

RECOMMENDATIONS

Energy Commission staff recommends that:

1. The Conditions of Certification proposed herein be adopted to ensure that the project is designed and constructed to assure public health and safety, and to ensure compliance with all applicable engineering LORS;

2. The project be designed and built to the 2001 CBSC (or successor standard, if such is in effect when the initial project engineering designs are submitted for review); and

3. The CBO shall review the final designs, conduct plan checking and perform field inspections during construction. Energy Commission staff shall audit and monitor the CBO to ensure satisfactory performance.

CONDITIONS OF CERTIFICATION

GEN-1 The project owner shall design, construct and inspect the project in accordance with the 1998 California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval. (The CBSC in effect is that edition that has been adopted by the California Building Standards Commission and published at least 180 days previously.) All transmission facilities (lines, switchyards, switching stations and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

In the event that the initial engineering designs are submitted to the CBO when a successor to the 1998 CBSC is in effect, the 1998 CBSC provisions identified herein shall be replaced with the applicable successor provisions. Where, in any specific case, different sections of the code specify different materials, methods of construction or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.

The project owner shall ensure that all contracts with contractors, subcontractors and suppliers shall clearly specify that all work performed and materials supplied on this project are to comply with the applicable codes listed above.

Verification: Within 30 days after execution of any contract or subcontract, the project owner shall submit to the CPM a copy of that portion of the contract or subcontract containing language specifying that work under that contract or subcontract shall comply with the applicable codes listed in this Condition of Certification. Within 30 days after receipt of the Certificate of Occupancy, the project owner shall submit to the CPM a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation and inspection requirements of the applicable LORS and the Energy Commission's Decision have been met in the area of facility design. The project owner shall provide the CPM a copy of the Certificate of Occupancy within 30 days of receipt from the CBO [1998 CBC, Section 109 – Certificate of Occupancy].

GEN-2 Prior to submittal of the initial engineering designs for CBO review, the project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List and a Master Specifications List. The schedule shall contain a list of proposed submittal packages of designs, calculations and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM when requested.

Verification: At least 60 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, the Master Drawing List and the Master Specifications List of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures and equipment listed in **Facility Design Table 1** below. Major structures and equipment shall be added to or deleted from the table only with CPM approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Structures and Equipment List

Equipment/System	Quantity (Plant)
Combustion Turbine (CT) Foundation and Connections	2
Combustion Turbine Generator Foundation and Connections	2
Steam Turbine (ST) Foundation and Connections	1
Steam Turbine Generator Foundation and Connections	1
Auxiliary Transformer Foundation and Connections	2
CT Inlet Air Plenum Structure, Foundation and Connections	2
Heat Recovery Steam Generator (HRSG) Structure, Foundation and Connections	2
HRSG Stack Structure, Foundation and Connections	2
Cooling Tower Structure, Foundation and Connections	1
Boiler Feed Pump Foundation and Connections	3
Condensate Extraction Pump Foundation and Connections	3
Circulating Water Pump Foundation and Connections	2
Steam Surface Condensers Foundation and Connections	2
Condenser Evacuation Pump Foundation and Connections	2
Turbine Hall Overhead Crane	1
Continuous Emission Monitoring System Structure, Foundation and Connections	2
Ammonia Storage System Foundation and Connections	1
Circulating Water System Dosing Foundation and Connections	1
Water Steam Cycle Dosing Foundation and Connections	1
High, Intermediate and Low Pressure Steam Systems	1 Lot
Reheat Steam System	1 Lot
Condensate and Feed Systems	1 Lot
Water Treatment System Brine Concentrator Foundation and Connections	1
Water Treatment System Demineralizer Foundation and Connections	1
Raw Water Storage Tank Foundation and Connections	1
Demineralized Water Storage Tank Foundation and Connections	1
Fuel Gas Heater Foundation and Connections	1
Natural Gas Compressor Foundation and Connections	1
Fire Protection System Pumps Foundation and Connections	2

Equipment/System	Quantity (Plant)
Workshop/Storage Building Structures, Foundation and Connections	1
Fire Pump House Foundation and Connections	1
Control Room Building Structures, Foundation and Connections	1
Boiler Feedwater Pump House Structures, Foundation and Connections	1
Secondary Unit Substation/Transformer	2
Combustion Turbine Electrical/Control Center	2
Steam Turbine Electrical/Control Center	2
Air Compressor Foundation and Connections	2
CT Static Starter Skid Foundation and Connections	2
Switchgear Equipment Building Structure, Foundation and Connections	2
CT Generator Step-up Transformer Foundation and Connections	2
ST Generator Step-up Transformer Foundation and Connections	1
Air Receiver Foundation and Connections	1
Air Dryer Foundation and Connections	1
Closed Cycle Cooling Water Heat Exchanger Foundation and Connections	2
Closed Cycle Cooling Water Pump Foundation and Connections	2
Potable Water Systems	1 Lot
Drainage Systems (including sanitary drain and waste)	1 Lot
High Pressure and Large Diameter Piping	1 Lot
HVAC and Refrigeration Systems	1 Lot
Temperature Control and Ventilation Systems (including water and sewer connections)	1 Lot
Building Energy Conservation Systems	1 Lot
Substation/Switchyard, Buses and Towers	1 Lot
Electrical Duct Banks	1 Lot

GEN-3 The project owner shall make payments to the CBO for design review, plan check and construction inspection based upon a reasonable fee schedule to be negotiated between the project owner and the CBO based on a CPM approved agreement. These fees may be consistent with the fees listed in the 2001 CBC [Chapter 1, Section 107 and Table 1-A, Building Permit Fees; Appendix Chapter 33, Section 3310 and Table A-33-A, Grading Plan Review Fees; and Table A-33-B, Grading Permit Fees], adjusted for inflation and other appropriate adjustments; may be based on the value of the facilities reviewed; may be based on hourly rates; or may be as otherwise agreed by the project owner and the CBO. Payments to the CBO shall in no way affect or diminish the independence of the CBO.

Verification: The project owner shall make the required payments to the CBO in accordance with the agreement between the project owner and the CBO. The project owner shall send a copy of the CBO's receipt of payment to the CPM in the next Monthly Compliance Report indicating that the applicable fees have been paid. The project owner shall provide a copy of the payment agreement to the CPM for review and approval prior to execution.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California registered architect, structural engineer or civil engineer, as a resident engineer (RE), to be in general responsible charge of the project [Building Standards Administrative Code (Cal. Code Regs., tit. 24, § 4-209, Designation of Responsibilities)]. All transmission facilities (lines, switchyards, switching stations and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided each part is clearly defined as a distinct unit. Separate assignment of general responsible charge may be made for each designated part.

The RE shall:

1. Monitor construction progress of work requiring CBO design review and inspection to ensure compliance with LORS;
2. Ensure that construction of all the facilities subject to CBO design review and inspection conforms in every material respect to the applicable LORS, these Conditions of Certification, approved plans, and specifications;
3. Prepare documents to initiate changes in the approved drawings and specifications when directed by the project owner or as required by conditions on the project;
4. Be responsible for providing the project inspectors and testing agency(ies) with complete and up-to-date set(s) of stamped drawings, plans, specifications and any other required documents;
5. Be responsible for the timely submittal of construction progress reports to the CBO from the project inspectors, the contractor, and other engineers who have been delegated responsibility for portions of the project; and
6. Be responsible for notifying the CBO of corrective action or the disposition of items noted on laboratory reports or other tests as not conforming to the approved plans and specifications.

The RE shall have the authority to halt construction and to require changes or remedial work, if the work does not conform to applicable requirements.

If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

Verification: At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval.

If the RE or the delegated engineer(s) are subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-5 Prior to the start of rough grading, the project owner shall assign at least one of each of the following California registered engineers to the project: A) a civil engineer; B) a soils engineer, or a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; and C) an engineering geologist. Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: D) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; E) a mechanical engineer; and F) an electrical engineer. [California Business and Professions Code section 6704 et seq., and sections 6730, 6731 and 6736 requires state registration to practice as a civil engineer or structural engineer in California.] All transmission facilities (lines, switchyards, switching stations and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer.

The project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all responsible engineers assigned to the project [2001 CBC, Section 104.2, Powers and Duties of Building Official].

If any one of the designated responsible engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned responsible engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

A. The civil engineer shall:

1. Review the Foundation Investigations Report, Geotechnical Report or Soils Report prepared by the soils engineer, the geotechnical engineer, or

by a civil engineer experienced and knowledgeable in the practice of soils engineering;

2. Design, or be responsible for design, stamp, and sign all plans, calculations and specifications for proposed site work, civil works and related facilities requiring design review and inspection by the CBO. At a minimum, these include: grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads and sanitary sewer systems; and
3. Provide consultation to the RE during the construction phase of the project and when necessary, recommend changes in the design of the civil works facilities and changes in the construction procedures.

B. The soils engineer, geotechnical engineer, or civil engineer experienced and knowledgeable in the practice of soils engineering, shall:

1. Review all the engineering geology reports;
2. Prepare the Foundation Investigations Report, Geotechnical Report or Soils Report containing field exploration reports, laboratory tests and engineering analysis detailing the nature and extent of the soils that may be susceptible to liquefaction, rapid settlement or collapse when saturated under load [2001 CBC, Appendix Chapter 33, Section 3309.5, Soils Engineering Report; Section 3309.6, Engineering Geology Report; and Chapter 18, Section 1804, Foundation Investigations];
3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2001 CBC, Appendix Chapter 33; Section 3317, Grading Inspections (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both); and
4. Recommend field changes to the civil engineer and RE.

This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform with predicted conditions used as a basis for design of earthwork or foundations [2001 CBC, section 104.2.4, Stop orders].

C. The engineering geologist shall:

1. Review all the engineering geology reports and prepare final soils grading report; and
2. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2001 CBC, Appendix Chapter 33; Section 3317, Grading Inspections (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both).

D. The design engineer shall:

1. Be directly responsible for the design of the proposed structures and equipment supports;
2. Provide consultation to the RE during design and construction of the project;
3. Monitor construction progress to ensure compliance with engineering LORS;
4. Evaluate and recommend necessary changes in design; and
5. Prepare and sign all major building plans, specifications and calculations.

E. The mechanical engineer shall be responsible for, and sign and stamp a statement with,each mechanical submittal to the CBO, stating that the proposed final design plans, specifications, and calculations conform with all of the mechanical engineering design requirements set forth in the Energy Commission's Decision.

F. The electrical engineer shall:

1. Be responsible for the electrical design of the project; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible civil engineer, soils (geotechnical) engineer and engineering geologist assigned to the project.

At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of construction, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible design engineer, mechanical engineer and electrical engineer assigned to the project.

The project owner shall notify the CPM of the CBO's approvals of the responsible engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, the project owner shall assign to the project, qualified and certified special inspector(s) who shall be responsible for the special inspections required by the 2001 CBC, Chapter 17 [Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection)]; and Section 106.3.5, Inspection and observation program. All transmission facilities (lines, switchyards, switching stations and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

The special inspector shall:

1. Be a qualified person who shall demonstrate competence, to the satisfaction of the CBO, for inspection of the particular type of construction requiring special or continuous inspection;
2. Observe the work assigned for conformance with the approved design drawings and specifications;
3. Furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction, then, if uncorrected, to the CBO and the CPM for corrective action [2001 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]; and
4. Submit a final signed report to the RE, CBO, and CPM, stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans and specifications and the applicable provisions of the applicable edition of the CBC.

A certified weld inspector, certified by the American Welding Society (AWS), and/or American Society of Mechanical Engineers (ASME) as applicable, shall inspect welding performed on-site requiring special inspection (including structural, piping, tanks and pressure vessels).

Verification: At least 15 days (or project owner and CBO approved alternative timeframe) prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next Monthly Compliance Report.

If the special inspector is subsequently reassigned or replaced, the project owner has five days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five days of the approval.

GEN-7 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend the corrective action required [2001 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this Condition of Certification and, if appropriate, the applicable sections of the CBC and/or other LORS.

Verification: The project owner shall transmit a copy of the CBO's approval of any corrective action taken to resolve a discrepancy to the CPM in the next Monthly

Compliance Report. If any corrective action is disapproved, the project owner shall advise the CPM, within five days, of the reason for disapproval and the revised corrective action to obtain the CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. The project owner shall notify the CPM after obtaining the CBO's final approval. The project owner shall retain one set of approved engineering plans, specifications and calculations (including all approved changes) at the project site or at another accessible location during the operating life of the project [1998 CBC, Section 106.4.2, Retention of Plans].

Verification: Within 15 days of the completion of any work, the project owner shall submit to the CBO, with a copy to the CPM, in the next Monthly Compliance Report, (a) a written notice that the completed work is ready for final inspection, and (b) a signed statement that the work conforms to the final approved plans. After storing final approved engineering plans, specifications and calculations as described above, the project owner shall submit to the CPM a letter stating that the above documents have been stored and indicate the storage location of such documents.

CIVIL-1 The project owner shall submit to the CBO for review and approval the following:

1. Design of the proposed drainage structures and the grading plan;
2. An erosion and sedimentation control plan;
3. Related calculations and specifications, signed and stamped by the responsible civil engineer; and
4. Soils Report, Geotechnical Report or Foundation Investigations Report required by the 2001 CBC [Appendix Chapter 33, Section 3309.5, Soils Engineering Report; Section 3309.6, Engineering Geology Report; and Chapter 18, Section 1804, Foundation Investigations].

Verification: At least 15 days (or project owner and CBO approved alternative timeframe) prior to the start of site grading the project owner shall submit the documents described above to the CBO for design review and approval. In the next Monthly Compliance Report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.

CIVIL-2 The resident engineer shall, if appropriate, stop all earthwork and construction in the affected areas when the responsible soils engineer, geotechnical engineer, or the civil engineer experienced and knowledgeable in the practice of soils engineering identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area [2001 CBC, Section 104.2.4, Stop orders].

<u>Verification:</u> The project owner shall notify the CPM within 24 hours, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within 24 hours of the CBO's approval to resume earthwork and construction in the affected areas, the project owner shall provide to the CPM a copy of the CBO's approval.

CIVIL-3 The project owner shall perform inspections in accordance with the 2001 CBC, Chapter 1, Section 108, Inspections; Chapter 17, Section 1701.6, Continuous and Periodic Special Inspection; and Appendix Chapter 33, Section 3317, Grading Inspection. All plant site-grading operations, for which a grading permit is required, shall be subject to inspection by the CBO.

If, in the course of inspection, it is discovered that the work is not being performed in accordance with the approved plans, the discrepancies shall be reported immediately to the resident engineer, the CBO and the CPM [2001 CBC, Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The project owner shall prepare a written report, with copies to the CBO and the CPM, detailing all discrepancies, non-compliance items, and the proposed corrective action.

<u>Verification:</u> Within five days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a Non-Conformance Report (NCR), and the proposed corrective action for review and approval. Within five days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs, for the reporting month, shall also be included in the following Monthly Compliance Report.

CIVIL-4 After completion of finished grading and erosion and sedimentation control and drainage work, the project owner shall obtain the CBO's approval of the final grading plans (including final changes) for the erosion and sedimentation control work. The civil engineer shall state that the work within his/her area of responsibility was done in accordance with the final approved plans [1998 CBC, Section 3318, Completion of Work].

<u>Verification:</u> Within 30 days (or project owner and CBO approved alternative timeframe) of the completion of the erosion and sediment control mitigation and drainage work, the project owner shall submit to the CBO, for review and approval, the final grading plans (including final changes) and the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes, with a copy of the transmittal letter to the CPM. The project owner shall submit a copy of the CBO's approval to the CPM in the next Monthly Compliance Report.

STRUC-1 Prior to the start of any increment of construction of any major structure or component listed in **Facility Design Table 1** of Condition of Certification **GEN-2**, above, the project owner shall submit to the CBO for design review and approval the proposed lateral force procedures for project structures and the applicable designs, plans and drawings for project structures. Proposed lateral force procedures, designs, plans and drawings shall be those for the following items (from **Table 1**, above):

1. Major project structures;
2. Major foundations, equipment supports and anchorage;
3. Large field fabricated tanks;
4. Turbine/generator pedestal; and
5. Switchyard structures.

Construction of any structure or component shall not commence until the CBO has approved the lateral force procedures to be employed in designing that structure or component.

The project owner shall:

1. Obtain approval from the CBO of lateral force procedures proposed for project structures;
2. Obtain approval from the CBO for the final design plans, specifications, calculations, soils reports and applicable quality control procedures. If there are conflicting requirements, the more stringent shall govern (i.e., highest loads, or lowest allowable stresses shall govern). All plans, calculations and specifications for foundations that support structures shall be filed concurrently with the structure plans, calculations and specifications [2001 CBC, Section 108.4, Approval Required];
3. Submit to the CBO the required number of copies of the structural plans, specifications, calculations and other required documents of the designated major structures prior to the start of on-site fabrication and installation of each structure, equipment support, or foundation [2001 CBC, Section 106.4.2, Retention of plans; and Section 106.3.2, Submittal documents];
4. Ensure that the final plans, calculations and specifications clearly reflect the inclusion of approved criteria, assumptions and methods used to develop the design. The final designs, plans, calculations and specifications shall be signed and stamped by the responsible design engineer [2001 CBC, Section 106.3.4, Architect or Engineer of Record]; and
5. Submit to the CBO the responsible design engineer's signed statement that the final design plans conform to the applicable LORS [2001 CBC, Section 106.3.4, Architect or Engineer of Record].

Verification: At least 60 days (or project owner and CBO approved alternative timeframe) prior to the start of any increment of construction of any structure or component listed in **Facility Design Table 1** of Condition of Certification **GEN-2** above, the project owner shall submit to the CBO the above final design plans, specifications and calculations, with a copy of the transmittal letter to the CPM.

The project owner shall submit to the CPM, in the next Monthly Compliance Report a copy of a statement from the CBO that the proposed structural plans, specifications and calculations have been approved and are in compliance with the requirements set forth in the applicable engineering LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval:

1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);
2. Concrete pour sign-off sheets;
3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);
4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and
5. Reports covering other structural activities requiring special inspections shall be in accordance with the 2001 CBC, Chapter 17, Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection); Section 1702, Structural Observation and Section 1703, Nondestructive Testing.

Verification: If a discrepancy is discovered in any of the above data, the project owner shall, within five days, prepare and submit an NCR describing the nature of the discrepancies and the proposed corrective action to the CBO, with a copy of the transmittal letter to the CPM [2001 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]. The NCR shall reference the Condition(s) of Certification and the applicable CBC chapter and section. Within five days of resolution of the NCR, the project owner shall submit a copy of the corrective action to the CBO and the CPM.

The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within 15 days. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action to obtain CBO's approval.

STRUC-3 The project owner shall submit to the CBO design changes to the final plans required by the 2001 CBC, Chapter 1, Section 106.3.2, Submittal documents and Section 106.3.3, Information on plans and specifications, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give to the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the Monthly Compliance Report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in Chapter 3, Table 3-E of the 2001 CBC shall, at a minimum, be designed to comply with the requirements of that Chapter.

Verification: At least 30 days (or project owner and CBO approved alternate timeframe) prior to the start of installation of the tanks or vessels containing the above specified quantities of toxic or hazardous materials, the project owner shall submit to the CBO for design review and approval final design plans, specifications and calculations, including a copy of the signed and stamped engineer's certification.

The project owner shall send copies of the CBO approvals of plan checks to the CPM in the following Monthly Compliance Report. The project owner shall also transmit a copy of the CBO's inspection approvals to the CPM in the Monthly Compliance Report following completion of any inspection.

MECH-1 The project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations for each plant major piping and plumbing system listed in **Facility Design Table 1**, Condition of Certification **GEN-2**, above. Physical layout drawings and drawings not related to code compliance and life safety need not be submitted. The submittal shall also include the applicable QA/QC procedures. Upon completion of construction of any such major piping or plumbing system, the project owner shall request the CBO's inspection approval of said construction [2001 CBC, Section 106.3.2, Submittal Documents; Section 108.3, Inspection Requests; Section 108.4, Approval Required; 2001 California Plumbing Code, Section 103.5.4, Inspection Request; Section 301.1.1, Approval].

The responsible mechanical engineer shall stamp and sign all plans, drawings and calculations for the major piping and plumbing systems subject to the CBO design review and approval, and submit a signed statement to the CBO when the proposed piping and plumbing systems have been designed, fabricated and installed in accordance with all of the applicable laws, ordinances, regulations and industry standards [Section 106.3.4, Architect or Engineer of Record], which may include, but not be limited to:

- American National Standards Institute (ANSI) B31.1 (Power Piping Code);
- ANSI B31.2 (Fuel Gas Piping Code);
- ANSI B31.3 (Chemical Plant and Petroleum Refinery Piping Code);
- ANSI B31.8 (Gas Transmission and Distribution Piping Code);
- Title 24, California Code of Regulations, Part 5 (California Plumbing Code);
- Title 24, California Code of Regulations, Part 6 (California Energy Code, for building energy conservation systems and temperature control and ventilation systems);
- Title 24, California Code of Regulations, Part 2 (California Building Code); and
- Specific City/County code.

The CBO may deputize inspectors to carry out the functions of the code enforcement agency [2001 CBC, Section 104.2.2, Deputies].

<u>Verification:</u> At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of any increment of major piping or plumbing construction listed in **Facility Design Table 1**, Condition of Certification **GEN-2** above, the project owner shall submit to the CBO for design review and approval the final plans, specifications and calculations, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

The project owner shall transmit to the CPM, in the Monthly Compliance Report following completion of any inspection, a copy of the transmittal letter conveying the CBO's inspection approvals.

MECH-2 For all pressure vessels installed in the plant, the project owner shall submit to the CBO and California Occupational Safety and Health Administration (Cal-OSHA), prior to operation, the code certification papers and other documents required by the applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection. ~~of said installation~~ [2001 CBC, Section 108.3, Inspection Requests].

The project owner shall:

1. Ensure that all boilers and fired and unfired pressure vessels are designed, fabricated and installed in accordance with the appropriate section of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, or other applicable code. Vendor certification, with identification of applicable code, shall be submitted for prefabricated vessels and tanks; and

2. Have the responsible design engineer submit a statement to the CBO that the proposed final design plans, specifications and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.

<u>Verification:</u> At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for design review and approval, the above listed documents, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM.

The project owner shall transmit to the CPM, in the Monthly Compliance Report following completion of any inspection, a copy of the transmittal letter conveying the CBO's and/or Cal-OSHA inspection approvals.

MECH-3 The project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations and quality control procedures for any heating, ventilating, air conditioning (HVAC) or refrigeration system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

The project owner shall design and install all HVAC and refrigeration systems within buildings and related structures in accordance with the CBC and other applicable codes. Upon completion of any increment of construction, the project owner shall request the CBO's inspection and approval. ~~of said construction~~. The final plans, specifications and calculations shall include approved criteria, assumptions and methods used to develop the design. In addition, the responsible mechanical engineer shall sign and stamp all plans, drawings and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications and calculations conform with the applicable LORS [2001 CBC, Section 108.7, Other Inspections; Section 106.3.4, Architect or Engineer of Record].

Verification: At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of construction of any HVAC or refrigeration system, the project owner shall submit to the CBO the required HVAC and refrigeration calculations, plans and specifications, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the CBC and other applicable codes, with a copy of the transmittal letter to the CPM.

ELEC-1 Prior to the start of any increment of electrical construction for electrical equipment and systems 480 volts and higher, listed below, with the exception of underground duct work and any physical layout drawings and drawings not related to code compliance and life safety, the project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations [CBC 2001, Section 106.3.2, Submittal documents]. Upon approval, the above listed plans, together with design changes and design change notices, shall remain on the site or at another accessible location for the operating life of the project. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS [2001 CBC, Section 108.4, Approval Required, and Section 108.3, Inspection Requests]. All transmission facilities (lines, switchyards, switching stations and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

A. Final plant design plans to include:

1. one-line diagrams for the 13.8 kV, 4.16 kV and 480 V systems; and
2. system grounding drawings.

B. Final plant calculations to establish:

1. short-circuit ratings of plant equipment;
2. ampacity of feeder cables;
3. voltage drop in feeder cables;
4. system grounding requirements;

5. coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
6. system grounding requirements; and
7. lighting energy calculations.

C. The following activities shall be reported to the CPM in the Monthly Compliance Report:
   1. Receipt or delay of major electrical equipment;
   2. Testing or energization of major electrical equipment; and
   3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission Decision.

Verification: At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of each increment of electrical construction, the project owner shall submit to the CBO for design review and approval the above listed documents. The project owner shall include in this submittal a copy of the signed and stamped statement from the responsible electrical engineer attesting compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

REFERENCES

BEP II (Caithness Blythe II, LLC/Looper). 2002b. Revised Application for Certification, Blythe Energy Project Phase II (02-AFC-1). Submitted to the California Energy Commission, July 03, 2002.

GEOLOGY, MINERAL RESOURCES, AND PALEONTOLOGY

Patrick A. Pilling, Ph.D., P.E., G.E.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the proposed Blythe Energy Project Phase II (BEP II) project regarding geologic hazards, geologic (including mineralogic), and paleontologic resources. Staff's objective is to ensure that there will be no significant adverse impacts to significant geological and paleontological resources during project construction, operation and closure. A brief geological and paleontological overview of the project is provided. The section concludes with staff's proposed monitoring and mitigation measures with respect to geologic hazards and geologic, mineralogic, and paleontologic resources, with the inclusion of Conditions of Certification.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The applicable LORS are listed in the Application for Certification (AFC), in Section 3.0, Table 3.0-1 of the AFC (Caithness Blythe II, LLC, 2002). The following is a brief description of the LORS for geologic hazards and resources, and paleontologic resources.

FEDERAL

The proposed BEP II is not located on federal land; however, an electrical transmission line will interconnect with the Western Area Power Administration (WAPA) Blythe I Substation. As such, there are no federal LORS for geological hazards and resources or grading for the BEP II plant site. Since it is expected that only electrical transmission lines will cross federally administered land within the Blythe Substation and this is not part of the proposed project, no federal LORS are anticipated to apply.

STATE AND LOCAL

The project shall be designed and constructed to the 2001 edition of the California Building Standards Code (CBSC). The CBSC includes a series of standards that are used in project investigation, design and construction (including grading and erosion control).

The "Measures for Assessment and Mitigation of Adverse Impacts to Non-renewable Paleontologic Resources: Standard Procedures" (Society of Vertebrate Paleontology [SVP], 1995) is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources. The measures were adopted in October 1995 by the Society of Vertebrate Paleontology (SVP), a national organization of professional scientists.

ENVIRONMENTAL SETTING

The proposed BEP II site is located within the Colorado Desert geomorphic province near the Colorado River and the California – Arizona state line. This area within the

Colorado Desert is characterized by the flood plain of the Colorado River and numerous flood terraces. The BEP II site is located on the Palo Verde Mesa, a flood terrace of the Colorado River. Major geologic units in the vicinity of the site include Tertiary and pre-Tertiary igneous, metamorphic, and sedimentary bedrock, Miocene to Pliocene fanglomerate [conglomerate], the Pliocene Bouse Formation, and Quaternary alluvium. The two water supply pipeline alternatives traverse Quaternary alluvium. The Pliocene to Pleistocene alluvium is also named the Chemehuevi Formation. The Miocene to Pliocene fanglomerate consists of cemented, poorly sorted gravel and sand. The Pliocene Bouse Formation consists of marine and brackish-water limestone and interbedded clays, silts, sands, and tufa (chemical sedimentary rock consisting of calcium carbonate or silica, deposited in solution in the water of a lake). The Quaternary alluvium consists of sands, gravels, silts, and clays.

Exploration at the plant site generally encountered a light to dark brown, medium dense to dense silty sand to poorly-graded sand to a depth of 111 feet. Ground water was encountered during exploration at a depth of approximately 88-1/2 feet below the ground surface.

ANALYSIS AND IMPACTS

There are two types of impacts considered in this section. The first are geologic hazards, which could impact proper functioning of the proposed facility and include faulting and seismicity, liquefaction, dynamic compaction, hydrocompaction, subsidence, expansive soils, landslides, and tsunamis and seiches. The second considers potential impacts the proposed facility could have on existing geologic, mineralogic, and paleontologic resources in the area.

STAFF'S CRITERIA FOR DETERMINING IMPACT SIGNIFICANCE

No federal LORS with respect to geologic hazards and geologic and mineralogic resources apply to this project; however, the California Building Standards Code (CBSC) provides geotechnical and geological investigation and design guidelines, which engineers must adhere to when designing a proposed facility. As a result, the criteria used to assess geologic hazard impact significance includes evaluating each potential hazard in relation to being able to adequately design and construct the proposed facility.

The California Environmental Quality Act Guidelines Appendix G provides a checklist of questions that a lead agency should normally address if relevant to a project's environmental impacts.

- Section (V) (c) asks if the project will directly or indirectly destroy a unique paleontological resource or site or unique geological feature.
- Sections (VI) (a), (b), (c), (d), and (e) pose questions that are focused on whether or not the project would expose persons or structures to geologic hazards.
- Sections (X) (a) and (b) pose questions about the project's effect on mineral resources.

With respect to impacts the proposed facility may have on existing geologic and mineralogic resources, geologic and mineral resource maps for the surrounding area have been reviewed, in addition to any site-specific information provided by the applicant, to determine if geologic and mineralogic resources are present in the area. When available, operating procedures of the proposed facility, in particular ground water extraction and mass grading operations, are reviewed to determine if such operations could adversely impact such resources.

Staff reviewed existing paleontologic information for the surrounding area, as well as any site-specific information provided by the applicant, in accordance with accepted assessment protocol (SVP, 1995) to determine if there are any known paleontologic resources in the general area. If present or likely to exist, Conditions of Certification are applied to project approval, which outlines procedures required during construction to mitigate impacts to potential resources.

GEOLOGIC HAZARDS

The AFC (Caithness Blythe II, LLC, 2002) provides documentation of potential geologic hazards at the BEPII plant site. Review of the AFC, coupled with our independent research, indicates the potential geologic hazards to impact the facility are low. Our independent research included review of available geologic maps, reports, and related data of the BEPII plant site and associated alternative linear facility areas. Geological information was available from the California Geological Survey (CGS), U. S. Geological Survey (USGS), and other governmental organizations.

Detailed geological discussion and information about the project's alternative linear facilities was not included in the AFC (Caithness Blythe II, LLC, 2002). However, given the geology and borings present at the BEPII plant site, potential for these geologic hazards along the linear facilities exists. In order to accurately assess the potential for liquefaction, dynamic compaction, hydrocompaction, subsidence, and expansive soils along the linear facilities, subsurface exploration and associated laboratory testing and analyses should be performed during the design-level geotechnical investigation per **Conditions of Certification GEN-1, GEN-5, and CIVIL-1 in the Facility Design** section. Although there are no current standards that require linear facilities to be designed to resist fault rupture or liquefaction, even when these facilities cross an active fault, it is prudent to address these constraints in the design-level investigations (Anderson, 2001).

Faulting and Seismicity

Energy Commission staff reviewed the California Geological Survey (CGS) publication *Fault Activity Map of California and Adjacent Areas with Locations and Ages of Recent Volcanic Eruptions*, dated 1994 (CGS, 1994); the *Geologic Map of California – Salton Sea Sheet* (CGS, 1967); the Late Pliocene – Quaternary (Post 4 m.y. Faults, Folds and Volcanic Rocks in Arizona (Scarborough et al., 1986); the *Geologic Map of Yuma County, Arizona* (Wilson, 1960); the Preliminary Geologic Map of the Blythe 30' by 60' Quadrangle, California and Arizona (Stone, 1990); and the *Maps of Known Active Fault Near-Source Zones in California and Adjacent Parts of Nevada* (International Conference of Building Officials [ICBO], 1998). The project is located within Seismic

Zone 3, as delineated on Figure 16-2 of the CBSC. The closest known Holocene (active) faults are the Brawley Fault, Elmore Ranch Fault, and the San Andreas Fault (Southern and Coachella segments), located approximately 61 miles southwest of the plant site. CEC staff has calculated an estimated deterministic peak horizontal ground acceleration for the Brawley Fault, Elmore Ranch fault, and the Southern and Coachella segments of the San Andreas Fault as 0.05g, 0.05g, 0.08g, and 0.08g, respectively. These estimates are based on a moment magnitude 6.5, 6.6, 7.4, and 7.4 earthquake on the Brawley Fault, Elmore Ranch fault, and the Southern and Coachella segments of the San Andreas Fault, respectively.

Liquefaction

Liquefaction is a nearly complete loss of soil shear strength that can occur during a seismic event. During the seismic event, cyclic shear stresses cause the development of excessive pore water pressure between the soil grains, effectively reducing the internal strength of the soil. This phenomenon is generally limited to unconsolidated, clean to silty sand (up to 35 percent non-plastic fines) and very soft silts lying below the ground water table. The higher the ground acceleration caused by a seismic event, the more likely liquefaction is to occur. Severe liquefaction can result in catastrophic settlements of overlying structural improvements and lateral spreading of the liquefied layer when confined vertically but not horizontally.

Ground water was encountered during exploration at a depth of approximately 88-1/2 feet below the ground surface at the plant site. Soils encountered during this exploration generally consist of medium dense to dense silty sand. With a water table greater than 50 feet in depth, there is no potential for liquefaction.

Dynamic Compaction

Dynamic compaction of soils results when relatively unconsolidated granular materials experience vibration associated with seismic events. The vibration causes a decrease in soil volume, as the soil grains tend to rearrange into a more dense state (an increase in soil density). The decrease in volume can result in settlement of overlying structural improvements. Since the plant site is generally underlain by medium dense to dense silty sand, the potential for dynamic compaction at the plant site is considered low.

Hydrocompaction

Partially saturated soils can possess bonds that are a result of chemical precipitates that accumulate under semi-arid conditions. Such soluble compound bonds provide the soils with cohesion and rigidity; however, these bonds can be destroyed upon prolonged submergence. When destroyed, a substantial decrease in the material’s void ratio is experienced even though the vertical pressure does not change. Materials that exhibit this decrease in void ratio and corresponding decrease in volume with the addition of water are defined as collapsible soils. Collapsible soils are typically limited to true loess, clayey loose sands, loose sands cemented by soluble salts, and windblown silts. Since the plant site is generally underlain by medium dense to dense silty sand, the potential for hydrocompaction at the plant site is considered low.

Subsidence

Ground subsidence is typically caused when ground water is drawn down by irrigation activities such that the effective unit weight of the soil mass is increased, which in turn increases the effective stress on underlying soils, resulting in consolidation/settlement of the underlying soils. The BEP II will obtain ground water from wells located at the plant site with drawdowns estimated to be less than 4 feet, as such; significant draw down of the water table due to BEP II operations is not anticipated. As a result, the potential for ground subsidence is considered low.

Expansive Soils

Soil expansion occurs when clay-rich soils, with an affinity for water, exist in-place at a moisture content below their plastic limit. The addition of moisture from irrigation, capillary tension, water line breaks, etc. causes the clay soils to collect water molecules in their structure, which, in turn, causes an increase in the overall volume of the soil. This increase in volume can correspond to movement of overlying structural improvements. As reported in the exploration logs, materials encountered in the project area consist of silty sand soils. As a result, the potential for expansive soils is low.

Landslides

Landslides typically involve rotational slump failures within surficial soils/colluvium and/or weakened bedrock that are usually implemented by an increase of the material's moisture content above a layer, which exhibits a relatively low strength. Debris-flows are shallow landslides that travel downslope very rapidly as muddy slurry. The BEP II site is relatively flat with up to approximately 25 feet of relief over the plant site and lies approximately 1 mile east of the edge of the Palo Verde Mesa. As a result, the potential impact of landslides to the BEP II site is low. There is some potential for a debris-flow driven by a flash flood and small landslides adjacent to the alternative water supply linear adjacent to the edge of the mesa near the pumping station. However, the flash flood would be caused by an unusually intense thunderstorm, which would be a low probability event.

Tsunamis and Seiches

Tsunamis and seiches are earthquake-induced waves, which inundate low-lying areas adjacent to large bodies of water. The proposed site is situated approximately 350 to 375 feet above mean sea level and no large bodies of water are present near the BEP II site or associated alternative linear facilities. As a result, the potential for tsunamis and seiches to affect the site is considered negligible.

GEOLOGIC, MINERALOGIC, AND PALEONTOLOGIC RESOURCES

Energy Commission staff have reviewed applicable geologic maps and reports for this area (Kohler-Anatablin, 1994; Clark, 1969; Larose, 1999; DOGGR, 1982; Saul et al., 1968; and CGS, 1980). Based on this information and the information contained in the AFC (Caithness Blythe II, LLC, 2002), there are no known mineralogic resources located at or immediately adjacent to the proposed BEP II site. An area of undeveloped warm thermal waters and several thermal wells are present in the Palo Verde Valley to the east (CGS, 1980). No other geologic resources are located at or immediately adjacent to the proposed BEP II site or associated alternative linear facilities. The applicant's consultant conducted a paleontologic resources field survey and a sensitivity analysis for the BEP I and BEP II plant sites. No significant fossil fragments were observed at the BEP II site; however, two vertebrate fossils were identified during construction of the BEP I project over five months of near-full-time monitoring. Surficial, older alluvium of the Chemehuevi Formation has been assigned a "high" sensitivity rating with respect to potentially containing paleontological resources. Based on this information and staff's review of available information (San Bernardino County Museum, 2002), the proposed BEP II site and associated alternative linear facilities have high potential to contain significant paleontologic resources.

PROJECT SPECIFIC IMPACTS

Seismicity represents the main geologic hazard at this site. **Conditions of Certification GEN-1**, **GEN-5**, **CIVIL-1 in the Facility Design** section should mitigate these impacts to a level of less than significant. No geologic or mineralogic resources are known to exist in the area. Paleontologic resources have been identified during construction of the BEP plant, and the (confidential) Paleontologic Resources Report (Caithness Blythe II, LLC, 2002) assigns a sensitivity rating of high for the older alluvium that underlies the proposed facility. Since the proposed project will include significant amounts of grading and a few fossils have been discovered at the adjacent BEP I plant site, staff considers the probability that paleontologic resources will be encountered during mass grading of the BEPII site and excavation for the alternative water supply linears to be high based on SVP assessment criteria. Conditions of Certification **PAL-1** to **PAL-7** are designed to mitigate any paleontological resource impacts, as discussed above, to a less than significant level.

CUMULATIVE IMPACTS

The BEPII site lies in an area that exhibits low geologic hazards and no known geologic or mineralogic resources. However, construction and operation of the BEP II project will likely require a new 118-mile electrical transmission line linking a new substation near the BEP I site with the Southern California Edison Company's Devers Substation, located near Palm Springs, California.

The Bureau of Land Management (BLM) has a recommended specific measure to mitigate paleontological impacts associated with the transmission line over federally administered land. The mitigation measure requires that a paleontologist develop a mitigation program. This measure is consistent with the Conditions of Certification recommended herein for this portion of the project. Based on this information and the proposed Conditions of Certification to mitigate potential project specific impacts, it is staff's opinion that the potential for significant adverse cumulative impacts to the project from geologic hazards, and to potential geologic, mineralogic, and paleontologic resources from the proposed project, is low.

FACILITY CLOSURE

A definition and general approach to closure is presented in the **General Conditions** section of this assessment. Facility closure activities are not anticipated to impact geologic, mineralogic, or paleontologic resources. This is due to the fact that no such resources are known to exist at the proposed project site. In addition, decommissioning and closure of the power plant should not negatively affect geologic, mineralogic, or paleontologic resources since the majority of the ground disturbed in plant decommissioning and closure will have been disturbed during construction and operation of the facility.

PROPOSED CONDITIONS OF CERTIFICATION

General Conditions of Certification with respect to Geology are covered under **Conditions of Certification GEN-1**, **GEN-5**, and **CIVIL-1** in the **Facility Design** section. Paleontological **Conditions of Certification PAL-1 through PAL-7** are identified below.

PAL-1 The project owner shall provide the Compliance Project Manager (CPM) with the resume and qualifications of its Paleontological Resource Specialist (PRS) for review and approval. If the approved PRS is replaced prior to completion of project mitigation and submittal of the Paleontological Resources Report, the project owner shall obtain CPM approval of the replacement PRS. The project owner shall submit to the CPM to keep on file, resumes of the qualified Paleontological Resource Monitors (PRMs). If a PRM is replaced, the resumes of the replacement PRM shall also be provided to the CPM.

The PRS resume shall include the names and phone numbers of references. The resume shall also demonstrate to the satisfaction of the CPM, the appropriate education and experience to accomplish the required paleontological resource tasks.

As determined by the CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the Society of Vertebrate Paleontology (SVP) guidelines of 1995. The experience of the PRS shall include the following:

1. Institutional affiliations, appropriate credentials and college degree; ability to recognize and collect fossils in the field;
2. local geological and biostratigraphic expertise;
3. proficiency in identifying vertebrate and invertebrate fossils and;
4. at least three years of paleontological resource mitigation and field experience in California, and at least one year of experience leading paleontological resource mitigation and field activities.

The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to monitor as he or she deems necessary on the project. Paleontologic resource monitors (PRMs) shall have the equivalent of the following qualifications:

- BS or BA degree in geology or paleontology and one year experience monitoring in California; or
- AS or AA in geology, paleontology or biology and four years experience monitoring in California; or

- Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit a resume and statement of availability of its designated PRS for on-site work.

At least 20 days prior to ground disturbance, the PRS or project owner shall provide a letter with resumes naming anticipated monitors for the project and stating that the identified monitors meet the minimum qualifications for paleontological resource monitoring required by the condition. If additional monitors are obtained during the project, the PRS shall provide additional letters and resumes to the CPM. The letter shall be provided to the CPM no later than one week prior to the monitor beginning on-site duties.

Prior to the termination or release of a PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval.

PAL-2 The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant, construction laydown areas, and all related facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and the plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings shall show the location, depth, and extent of all ground disturbances and should be of such as scale to allow the PRS to determine and map fossil occurrences. If the footprint of the power plant or linear facility changes, the project owner shall provide maps and drawings reflecting these changes to the PRS and CPM.

If construction of the project will proceed in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and CPM. Prior to work commencing on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes.

At a minimum, the project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked during the next week, until ground disturbance is completed.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings to the PRS and CPM.

If there are changes to the footprint of the project, revised maps and drawings shall be provided to the PRS and CPM at least 15 days prior to the start of ground disturbance.

If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.

PAL-3 The project owner shall ensure that the PRS prepares, and the project owner submits to the CPM for review and approval, a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting and sampling activities and may be modified with CPM approval. This document shall be used as a basis for discussion in the event that on-site decisions or changes are proposed. Copies of the PRMMP shall reside with the PRS, each monitor, the project owner's on-site manager, and the CPM.

The PRMMP shall be developed in accordance with the guidelines of the Society of Vertebrate Paleontology (SVP, 1995) and shall include, but not be limited to, the following:

1. Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking; construction monitoring; mapping and data recovery; fossil preparation and collection; identification and inventory; preparation of final reports; and transmittal of materials for curation will be performed according to the PRMMP procedures;
2. Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and the Conditions of Certification;
3. A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units;
4. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed schedule for the monitoring and sampling;
5. A discussion of the procedures to be followed in the event of a significant fossil discovery, halting construction, resuming construction, and how notifications will be performed;
6. A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;
7. Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meets the Society of Vertebrate Paleontology standards and requirements for the curation of paleontological resources;
8. Identification of the institution that has agreed to receive any data and fossil materials collected, requirements or specifications for materials delivered for curation and how they will be met, and the name and phone number of the contact person at the institution; and
9. A copy of the paleontological Conditions of Certification.

<u>Verification:</u> At least (30) days prior to ground disturbance, the project owner shall provide two copies of the PRMMP to the CPM. The PRMMP shall include an affidavit of authorship by the PRS, and acceptance of the PRMMP by the project owner evidenced by a signature.

PAL-4 Prior to ground disturbance and for the duration of construction, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for all recently employed project managers, construction supervisors and workers who are involved with or operate ground disturbing equipment or tools and who have not previously had the training. Workers shall not excavate in sensitive units prior to receiving CPM-approved worker training. Worker training shall consist of an initial in-person PRS training during the project kick-off for those mentioned above. Following initial training, a CPM-approved video or in-person training may be used for new employees. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or any other areas of interest or concern.

The Worker Environmental Awareness Program (WEAP) shall address the potential to encounter paleontological resources in the field, the sensitivity and importance of these resources, and the legal obligations to preserve and protect such resources.

The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Good quality photographs or physical examples of vertebrate fossils shall be provided for project sites containing units of high sensitivity;
3. Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;
4. Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. A Certification of Completion of WEAP form signed by each worker indicating that they have received the training; and
7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

<u>Verification:</u> At least 30 days prior to ground disturbance, the project owner shall submit two copies of the proposed WEAP including the brochure with the set of reporting procedures the workers are to follow.

At least 30 days prior to ground disturbance, the project owner shall submit the script and final video to the CPM for approval if the project owner is planning on using a video for interim training.

If an alternate paleontological trainer is requested by the project owner, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval prior to installation of the alternate trainer. Alternate trainers shall not conduct training prior to CPM authorization.

In the Monthly Compliance Report (MCR) the project owner shall provide copies of the WEAP Certification of Completion forms with the names of those trained and the trainer or type of training offered that month. The MCR shall also include a running total of all persons who have completed the training to date.

PAL-5 The project owner shall ensure that the PRS and PRM(s) monitor consistently with the PRMMP all construction-related grading, excavation, trenching, and augering in areas where potentially fossil-bearing materials have been identified. In the event that the PRS determines full time monitoring is not necessary in locations that were identified as potentially fossil-bearing in the PRMMP, the project owner shall notify and seek the concurrence of the CPM.

The project owner shall ensure that the PRS and PRM(s) have the authority to halt or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1. Any change of monitoring different from the accepted program presented in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the CPM prior to the change in monitoring. The letter or email shall include the justification for the change in monitoring and be submitted to the CPM for review and approval.

2. The project owner shall ensure that the PRM(s) keeps a daily log of monitoring of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the CPM at any time.

3. The project owner shall ensure that the PRS immediately notifies the CPM of any incidents of non-compliance with any paleontological resources Conditions of Certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the Conditions of Certification.

4. For any significant paleontological resources encountered, either the project owner or the PRS shall notify the CPM immediately (no later than the following morning after the find, or Monday morning in the case of a weekend) of any halt of construction activities.

The project owner shall ensure that the PRS prepares a summary of the monitoring and other paleontological activities that will be placed in the Monthly Compliance Reports (MCR). The summary will include the name(s) of PRS or PRM(s) active during the month, general descriptions of training and monitored construction activities and general locations of excavations, grading, etc. A section of the report shall include the geologic units or subunits encountered; descriptions of sampling within each unit; and a list of identified fossils. A final section of the report shall address any issues or concerns about the project relating to paleontologic monitoring including any incidents of non-compliance and any changes to the monitoring plan that have been approved by the CPM. If no monitoring took place during the month, the report shall include an explanation in the summary as to why monitoring was not conducted.

Verification: The project owner shall ensure that the PRS submits the summary of monitoring and paleontological activities in the MCR. When feasible, the CPM shall be notified 10 days in advance of any proposed changes in monitoring different from the plan identified in the PRMMP. If there is any unforeseen change in monitoring, the notice shall be given as soon as possible prior to implementation of the change.

PAL-6 The project owner, through the designated PRS, shall ensure that all components of the PRMMP are adequately performed including collection of fossil materials, preparation of fossil materials for analysis, analysis of fossils, identification and inventory of fossils, the preparation of fossils for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during the project construction.

Verification: The project owner shall maintain in their compliance file copies of signed contracts or agreements with the designated PRS and other qualified research specialists. The project owner shall maintain these files for a period of three years after completion and approval of the CPM-approved Paleontological Resource Report (See **PAL-7**). A signed contract or agreement with the PRS shall be provided to the CPM upon request. The project owner shall be responsible to pay any curation fees charged by the museum for fossils collected and curated as a result of paleontological mitigation. A copy of the letter of transmittal submitting the fossils to the curating institution shall be provided to the CPM.

PAL-7 The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground disturbing activities. The PRR shall include an analysis of the collected fossil materials and related information and submitted to the CPM for review and approval.

The report shall include, but is not limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated.

Verification: Within (90) days after completion of ground disturbing activities, including landscaping, the project owner shall submit the Paleontological Resources Report under confidential cover to the CPM.

Certification of Completion of Worker Environmental Awareness Program
BLYTHE ENERGY PROJECT II (02-AFC-4)

This is to certify these individuals have completed a mandatory California Energy Commission-approved Worker Environmental Awareness Program (WEAP). The WEAP includes pertinent information on Cultural, Paleontology and Biological Resources for all personnel (i.e. construction supervisors, crews and plant operators) working on-site or at related facilities. By signing below, the participant indicates that they understand and shall abide by the guidelines set forth in the Program materials. Please include this completed form in the Monthly Compliance Report.

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Cul Trainer: ________________ Signature:_________________________ Date: ___/___/____
PaleoTrainer: _______________ Signature:_________________________ Date: ___/___/____
Bio Trainer: ________________ Signature:_________________________ Date: ___/___/____

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POWER PLANT EFFICIENCY

Kevin Robinson and Steve Baker

INTRODUCTION

The Energy Commission makes findings as to whether energy use by the Blythe Energy Project Phase II (BEP II) will result in significant adverse impacts on the environment, as defined in the California Environmental Quality Act (CEQA). If the Energy Commission finds that the BEP II's consumption of energy creates a significant adverse impact, it must determine whether there are any feasible mitigation measures that could eliminate or minimize the impact. In this analysis, staff addresses the issue of inefficient and unnecessary consumption of energy.

In order to support the Energy Commission's findings, this analysis will:

∉ examine whether the facility will likely present any adverse impacts upon energy resources;

∉ examine whether these adverse impacts are significant; and if so,

∉ examine whether feasible mitigation measures exist that would eliminate the adverse impacts, or reduce them to a level of insignificance.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

No federal LORS apply to the efficiency of this project.

STATE

No State LORS apply to the efficiency of this project.

LOCAL

No local or county ordinances apply to power plant efficiency.

SETTING

Caithness Blythe II proposes to construct and operate the 520 MW (nominal gross output) combined cycle, merchant BEP II power plant to generate baseload and load following power, selling energy to the power market (Blythe 2002b, AFC §§ 1.1, 2.1, 2.2.2, 2.2.16.1, 8.3.2, 8.4). (Note that this nominal rating is based upon preliminary design information and generating equipment manufacturers' guarantees. The project's actual maximum generating capacity may differ from this figure.) The BEP II will consist of two Siemens Westinghouse V84.3a 170 MW F-class combustion gas turbines with a chilled water inlet air cooling system or an evaporative inlet air cooling system (Blythe 2003a, AFC §§ 2.0, 2.2.4.1.1), two multi-pressure heat recovery steam generators (HRSGs) with duct burners, and one single 3-pressure, reheat, condensing steam turbine (ST) generator producing a maximum of 180 MW, arranged in a two-on-one combined cycle train, totaling approximately 520 MW. The gas turbines and HRSGs will be equipped with dry low-NOx combustors and selective catalytic reduction to control air emissions (Blythe 2002b, AFC §§ 1.1.1, 2.2.2, 2.2.12). Natural gas will be delivered by the existing El Paso Natural Gas Company (EPNGC) gas distribution system through a new pipeline connection to the approved Blythe Energy Project I gas supply system (Blythe 2002b, AFC §§ 1.1.1, 2.2.7, 6.4, 8.3.1, Fig. 2.0-17).

ANALYSIS

CEQA Guidelines state that the environmental analysis "…shall describe feasible measures which could minimize significant adverse impacts, including where relevant, inefficient and unnecessary consumption of energy" (Cal. Code Regs., tit. 14, § 15126.4(a)(1)). Appendix F of the Guidelines further suggests consideration of such factors as the project's energy requirements and energy use efficiency; its effects on local and regional energy supplies and energy resources; its requirements for additional energy supply capacity; its compliance with existing energy standards; and any alternatives that could reduce wasteful, inefficient and unnecessary consumption of energy (Cal. Code regs., tit. 14, § 15000 et seq., Appendix F).

ADVERSE IMPACTS ON ENERGY RESOURCES

The inefficient and unnecessary consumption of energy, in the form of non-renewable fuels such as natural gas and oil, constitutes an adverse environmental impact. An adverse impact can be considered significant if it results in:

- adverse effects on local and regional energy supplies and energy resources;
- a requirement for additional energy supply capacity;
- noncompliance with existing energy standards; or
- the wasteful, inefficient and unnecessary consumption of fuel or energy.

Project Energy Requirements And Energy Use Efficiency

Any power plant large enough to fall under Energy Commission siting jurisdiction will consume large amounts of energy. Under normal conditions, the BEP II will burn natural gas at a nominal rate of 84,400 MMBtu per day, lower heating value (LHV) (Blythe 2002b, AFC § 2.2.7). This is a substantial rate of energy consumption, and holds the potential to impact energy supplies. Under expected project conditions, electricity will be generated at a full load efficiency of between approximately 55 and 58 percent LHV (Blythe 2002b, AFC § 8.4, Figures 2.0-6A, Figure 2.0-6B, Figure 2.0-6C, Figure 2.0-6D); compare this to the average fuel efficiency of a typical utility company baseload power plant at approximately 35 percent LHV.

Adverse Effects On Energy Supplies And Resources

The Applicant has described its sources of supply of natural gas for the project (Blythe 2002b, AFC §§ 1.1.1, 2.2.7, 8.3.1). Natural gas for the BEP II will be supplied from the existing EPNGC system via a new pipeline connection to the approved BEP I gas supply system. The EPNGC system is capable of delivering the required quantity of gas to the BEP II. The El Paso natural gas supply represents a reliable source of natural gas for this project. It is therefore highly unlikely that the project could pose a substantial increase in demand for natural gas in California.

Additional Energy Supply Requirements

Natural gas fuel will be supplied to the project by the EPNGC via a new pipeline connection to the approved BEP I gas supply system (Blythe 2002b, AFC §§ 1.1.1, 2.2.7, 8.3.1). There is no real likelihood that the BEP II will require the development of additional energy supply capacity.

Compliance With Energy Standards

No standards apply to the efficiency of the BEP II or other non-cogeneration projects.

Alternatives To Reduce Wasteful, Inefficient And Unnecessary Energy Consumption

The BEP II could be deemed to create significant adverse impacts on energy resources if alternatives existed that would reduce the project's use of fuel. Evaluation of alternatives to the project that could reduce wasteful, inefficient or unnecessary energy consumption first requires examination of the project's energy consumption. Project fuel efficiency, and therefore its rate of energy consumption, is determined by the configuration of the power producing system and by the selection of equipment used to generate power.

Project Configuration

The BEP II will be configured as a combined cycle power plant, in which electricity is generated by two gas turbines, and additionally by a reheat steam turbine that operates on heat energy recuperated from the gas turbines' exhaust (Blythe 2002b, AFC §§ 1.1, 1.1.1, 2.1, 2.2.2). By recovering this heat, which would otherwise be lost up the exhaust stacks, the efficiency of any combined cycle power plant is increased considerably from that of either gas turbines or steam turbines operating alone. Such a configuration is well suited to the large, steady loads met by a baseload plant, intended to supply energy efficiently for long periods of time.

The Applicant proposes to use inlet air coolers, HRSG duct burners (re-heaters), three-pressure HRSGs and a steam turbine unit and circulating cooling water system (Blythe 2002b, AFC §§ 1.1, 1.1.1, 2.1, 2.2.2, 2.2.4.1.1, 2.2.4.2, 2.2.4.3). Staff believes these features contribute to meaningful efficiency enhancement to the BEP II. The two-train combustion turbine (CT)/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT instead of having two CTs operating at an inefficient 50 percent load.

The BEP II includes HRSG duct burners, partially to replace heat to the ST cycle during high ambient temperatures when CT capacity drops, and partially for added power. Duct firing also provides a number of operational benefits, such as load following and balancing and optimizing the operation of the ST cycle.

Equipment Selection

The F-class of advanced gas turbines to be employed in the BEP II represent some of the most modern and efficient such machines now available. The applicant will employ two Siemens-Westinghouse V84.3a advanced F-class combustion gas turbine generators in a two-on-one combined cycle power train nominally rated at 520 MW and 58 percent efficiency LHV (Blythe 2002b, AFC §§ 1.1, 1.1.1, 2.1, 2.2.2, 2.2.4.1.1, 8.4).

One possible alternative is the Siemens-Westinghouse 501F, nominally rated in a two-on-one train combined cycle configuration at 568 MW and 56.3 percent efficiency LHV at ISO conditions (GTW 2002).

Another alternative is the General Electric GE 7FA, nominally rated in a two-on-one train combined cycle configuration at 530 MW and 56.5 percent efficiency LHV (GTW 2002).

Any differences among the V84.3a, GE 7FA, and W501FD in actual operating efficiency will be insignificant. Selecting among these machines is thus based on other factors, such as generating capacity, cost, commercial availability, and ability to meet air pollution limitations.

Efficiency Of Alternatives To The Project

The project objectives include generation of baseload electricity and ancillary services, as market conditions dictate (Blythe 2002b, AFC §§ 1.1, 2.2.2, 2.2.16.1, 2.4.1, 6.7, 8.3.2, 8.4).

Alternative Generating Technologies

Alternative generating technologies for the BEP II are considered in the AFC (Blythe 2002b, AFC § 6.7.2, Table 6.0-3, Table 6.0-4). Fossil fuels, nuclear, solar, hydroelectric, and biomass technologies are all considered. Given the project objectives, location, and air pollution control requirements, staff agrees with the applicant that only natural gas-burning technologies are feasible.

Natural Gas-Burning Technologies

Fuel consumption is one of the most important economic factors in selecting an electric generator; fuel typically accounts for over two-thirds of the total operating costs of a fossil fuel-fired power plant (Power 1994). Under a competitive power market system, where operating costs are critical in determining the competitiveness and profitability of a power plant, the plant owner is thus strongly motivated to purchase fuel-efficient machinery.

Modern gas turbines embody the most fuel-efficient electric generating technology available today. Currently available, large combustion turbine models can be grouped into three categories including conventional, advanced, and next generation. Advanced combustion turbines offer advantages for the BEP II. Their higher firing temperatures offer higher efficiencies than conventional turbines. They offer proven technology with numerous installations and extensive run time in commercial operation. Emission levels are also proven, and guaranteed emission levels have been reduced based on operational experience and design optimization by the manufacturers (Blythe 2002b, AFC §§ 1.1.1, 2.2.2, 2.2.12.1).

One possible alternative to an advanced F-class gas turbine is the next generation G-class machine, such as the Siemens-Westinghouse 501G gas turbine generator, which employs partial steam cooling to allow slightly higher temperatures, yielding slightly greater efficiency. In actual operation, one would expect to see the difference in efficiency narrow, as the larger capacity G-class turbines would run at less than optimum (full) output more frequently than the smaller capacity F-class turbines. (Gas turbine efficiency drops rapidly at less then full load.) The W501G is still relatively new; the first such machine began simple cycle operation at a site in Florida owned by Lakeland Electric and Water on April 16, 2001 and at PG&E Generating's Millennium combined cycle project in Charlton, Massachusetts on April 5, 2001 (GTW 2001). Given the minor efficiency improvement promised by the G-class turbine and the lack of a proven track record for the W501G, the applicant's decision to purchase F-class machines is a reasonable one.

Capital cost is also important in selecting generating machinery. Recent progress in the development of large, stationary gas turbines, aided by the incorporation into these machines of technological advances made in the development of aircraft (jet) engines, has created a situation in which several large manufacturers compete vigorously to sell their machines. This, combined with the cost advantages of assembly line manufacturing, has driven down the prices of these machines. Thus, the power plant developer can purchase a turbine generator that not only offers the lowest available fuel costs, but at the same time sells for the lowest per-kilowatt capital cost.

Inlet Air Cooling

A further choice of alternatives involves the selection of gas turbine inlet air cooling methods. The two commonly used techniques are the evaporative cooler or fogger, and the chiller; both devices increase power output by cooling the gas turbine inlet air. A mechanical chiller can offer greater power output than the evaporative cooler on hot, humid days, but consumes electric power to operate its refrigeration process, thus slightly reducing overall net power output and, thus, overall efficiency. An absorption chiller uses less electric power, but necessitates the use of a substantial inventory of ammonia. An evaporative cooler or a fogger boosts power output best on dry days; it uses less electric power than a mechanical chiller, possibly yielding slightly higher operating efficiency. The difference in efficiency among these techniques is relatively insignificant.

Given the climate at the project site and the relative lack of clear superiority of one system over the other, staff agrees that either choice of gas turbine inlet air cooling methods will yield no significant adverse energy impacts.

Conclusions on Efficiency of Alternatives

In conclusion, the project configuration (combined cycle) and generating equipment (F-class gas turbines) chosen appear to represent the most efficient feasible combination to satisfy the project objectives. The two-train CT/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT instead of having two CTs operating at an inefficient 50 percent load. This offers an efficiency advantage over the larger machines during unit turndown. There are no alternatives that could significantly reduce energy consumption.

Staff, therefore, believes the BEP II will not constitute a significant adverse impact on energy resources.

CUMULATIVE IMPACTS

BEP I presently operates a nearby power plant project that holds the potential for cumulative energy consumption impacts when aggregated with the project. Staff knows of no other projects that could result in cumulative energy impacts.

Staff believes that construction and operation of the project will not bring about indirect impacts, in the form of additional fuel consumption, that would not have occurred but for the project. The older, less efficient power plants consume more natural gas to operate than the new, more efficient plants such as the BEP II. Since natural gas will be burned by the power plants that are most competitive on the spot market, the most efficient plants will run the most. The high efficiency of the proposed BEP II should allow it to compete very favorably, running at a high capacity factor, replacing less efficient power generating plants in the market, and therefore not impacting or even reducing the cumulative amount of natural gas consumed for power generation.

FACILITY CLOSURE

Closure of the facility, whether planned or unplanned, will not influence, nor will it be influenced by, project efficiency. Any efficiency impacts due to closure of the project would be on the electric system as a whole. Yet the vast size of the electric system serving California, the number of generating plants offering to sell power into it, and the existence of the California Independent System Operator to ensure the efficient management of the system, all lend assurance that closure of this facility will not produce significant adverse impacts on efficiency.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The project, if constructed and operated as proposed, would generate a nominal 520 MW of electric power at an overall project fuel efficiency between 55 and 58 percent LHV. While it will consume substantial amounts of energy, it will do so in the most efficient manner practicable. It will not create significant adverse effects on energy supplies or resources, will not require additional sources of energy supply, and will not consume energy in a wasteful or inefficient manner. No energy standards apply to the project. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

No cumulative impacts on energy resources are likely. Facility closure would not likely present significant impacts on electric system efficiency.

RECOMMENDATION

No Conditions of Certification are proposed.

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POWER PLANT RELIABILITY

Kevin Robinson and Steve Baker

INTRODUCTION

In this analysis, Energy Commission staff addresses the reliability issues of the project to determine if the power plant is likely to be built in accordance with typical industry norms for reliability of power generation. Staff uses this level of reliability as a benchmark because it ensures that the resulting project would likely not degrade the overall reliability of the electric system it serves (see **Setting** below).

The scope of this power plant reliability analysis covers:

- equipment availability;
- plant maintainability;
- fuel and water availability; and
- power plant reliability in relation to natural hazards.

Staff examined the project design criteria to determine if the project is likely to be built in accordance with typical industry norms for reliability of power generation. While Caithness Blythe II has predicted a 92 to 98 percent availability for the Blythe Energy Project Phase II (see below), staff uses the benchmark identified above, rather than Caithness Blythe II's projection, to evaluate the project's reliability.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Presently, there are no laws, ordinances, regulations or standards (LORS) that establish either power plant reliability criteria or procedures for attaining reliable operation. However, the commission must make findings as to the manner in which the project is to be designed, sited and operated to ensure safe and reliable operation (Cal. Code Regs., tit. 20, § 1752(c)). Staff takes the approach that a project is acceptable if it does not degrade the reliability of the utility system to which it is connected. This is likely the case if the project exhibits reliability at least equal to that of other power plants on that system (see **Setting** below).

SETTING

In the regulated monopoly electric industry of past decades, the utility companies assured overall system reliability, in part, by maintaining a "reserve margin." This amounted to having on call, at all times, sufficient generating capacity, in the form of standby power plants, to quickly handle unexpected outages of generating or transmission facilities. The utilities generally maintained a seven- to ten-percent reserve margin, meaning that sufficient capacity was on call to quickly replace from seven to ten percent of total system resources. This margin proved adequate, in part because of the reliability of the power plants that constituted the system.

Now, in the restructured competitive electric power industry, the responsibility for maintaining system reliability falls largely to the California Independent System Operator (Cal-ISO), an entity that purchases, dispatches, and sells electric power throughout the state. How Cal-ISO will ensure system reliability is still being determined; protocols are being developed and put in place that will, it is anticipated, allow sufficient reliability to be maintained under the competitive market system. "Must-run" power purchase agreements and "participating generator" agreements are two mechanisms being employed to ensure an adequate supply of reliable power (Mavis 1998, pers. comm.).

The Cal-ISO also requires those power plants selling ancillary services, as well as those holding reliability must-run contracts, to fulfill certain requirements, including:

- filing periodic reports on plant reliability;
- reporting all outages and their causes; and
- scheduling all planned maintenance outages with the Cal-ISO (Detmers 1999, pers. comm.).

The Cal-ISO's mechanisms to ensure adequate power plant reliability apparently have been devised under the assumption that the individual power plants that compete to sell power into the system will each exhibit a level of reliability similar to that of power plants of past decades. However, there is cause to believe that, under free market competition, financial pressures on power plant owners to minimize capital outlays and maintenance expenditures may act to reduce the reliability of many power plants, both existing and newly constructed (McGraw-Hill 1994). It is possible that, if significant numbers of power plants exhibit individual reliability sufficiently lower than this historical level, the assumptions used by Cal-ISO to ensure system reliability will prove invalid, with potentially disappointing results. Until the restructured competitive electric power system has undergone a shakeout period, and the effects of varying power plant reliability are thoroughly understood and compensated for, staff deems it wise to encourage power plant owners to continue to build and operate their projects to the level of reliability to which all in the industry are accustomed.

Blythe Energy proposes to operate the 520 MW (nominal output) Blythe Energy Project Phase II (BEP II), selling energy and capacity to the power market (Blythe 2002b, AFC §§ 1.1, 2.1, 2.2.16.1, 8.4). The project is expected to operate at an overall availability in the range of 92 to 98 percent (Blythe 2002b, AFC § 8.3.2), and at a capacity factor, over the life of the plant, of 30-100 percent of base load (Blythe 2002b, AFC § 2.4.1).

ANALYSIS

The availability factor for a power plant is the percentage of the time that it is available to generate power; both planned and unplanned outages subtract from its availability. Measures of power plant reliability are based on its actual ability to generate power when it is considered available and are based on starting failures and unplanned, or forced, outages. For practical purposes, reliability can be considered a combination of these two industry measures, making a reliable power plant one that is available when called upon to operate. Throughout its intended 30-year life (Blythe 2002b, AFC §§ 2.4.1, 8.3.2), the BEP II will be expected to perform reliably. Power plant systems must be able to operate for extended periods without shutting down for maintenance or repairs. Achieving this reliability is accomplished by ensuring adequate levels of equipment availability, plant maintainability with scheduled maintenance outages, fuel and water availability, and resistance to natural hazards. Staff examines these factors for the project and compares them to industry norms. If they compare favorably, staff can conclude that the BEP II will be as reliable as other power plants on the electric system, and will therefore not degrade system reliability.

EQUIPMENT AVAILABILITY

Equipment availability will be ensured by use of appropriate quality assurance/ quality control (QA/QC) programs during design, procurement, construction and operation of the plant, and by providing for adequate maintenance and repair of the equipment and systems (discussed below).

Quality Control Program

Blythe Energy describes a QA/QC program (Blythe 2002b, AFC §§ 2.4, 2.4.1, 8.3.2) typical of the power industry. Equipment will be purchased from qualified suppliers, based on technical and commercial evaluations. Suppliers' personnel, production capability, past performance, QA programs and quality history will be evaluated. The project owner will perform receipt inspections, test components, and administer independent testing contracts. Staff expects implementation of this program to yield typical reliability of design and construction. To ensure such implementation, staff has proposed appropriate conditions of certification under the portion of this document entitled **Facility Design**.

PLANT MAINTAINABILITY

Equipment Redundancy

A generating facility called on to operate in baseload service for long periods of time must be capable of being maintained while operating. A typical approach for achieving this is to provide redundant examples of those pieces of equipment most likely to require service or repair.

Blythe Energy plans to provide appropriate redundancy of function for the combined cycle portion of the project (Blythe 2002b, AFC §§ 2.2.6, 2.4.2, 8.3.4). The fact that the project consists of two trains of gas turbine generators/HRSGs provides inherent reliability. Failure of a non-redundant component of one train should not cause the other train to fail, thus allowing the plant to continue to generate (at reduced output). Further, the plant's distributed control system (DCS) will be built with typical redundancy. Emergency DC and AC power systems will be supplied by redundant batteries, chargers, and inverters. Other balance of plant equipment will be provided with redundant examples, including:

- three 50 percent feedwater pumps;
- three 50 percent condensate pumps;
- two 60 percent circulating water pumps; and

- two 100 percent air compressors.

With this opportunity for continued operation in the face of equipment failure, staff believes that equipment redundancy will be sufficient for a project such as this.

Maintenance Program

Blythe Energy proposes to establish a preventive plant maintenance program typical of the industry (Blythe 2002b, AFC § 2.4.1). Equipment manufacturers provide maintenance recommendations with their products; the applicant will base its maintenance program on these recommendations. The program will encompass preventive and predictive maintenance techniques. Maintenance outages will be planned for periods of low electricity demand. In light of these plans, staff expects that the project will be adequately maintained to ensure acceptable reliability.

FUEL AND WATER AVAILABILITY

For any power plant, the long-term availability of fuel and of water for cooling or process use is necessary to ensure reliability. The need for reliable sources of fuel and water is obvious; lacking long--term availability of either source, the service life of the plant may be curtailed, threatening the supply of power as well as the economic viability of the plant.

Fuel Availability

The BEP II will burn natural gas from the El Paso Natural Gas Company (EPNGC) distribution system. Gas will be transmitted to the plant via a new pipeline connection to the approved BEP I gas supply system (Blythe 2002b, AFC §§ 1.1.1, 2.2.7, 6.4, 8.3.1, Figure 2.0-17). This EPNGC natural gas system represents a reliable source of considerable capacity. This system offers access to adequate supplies of gas (Blythe 2002b, AFC § 8.3.1). Staff agrees with the applicant's prediction that there will be adequate natural gas supply and pipeline capacity to meet the project's needs.

Water Supply Reliability

The BEP II will obtain water from an additional well constructed on-site which will supply cooling water for the steam turbine condenser and inlet air cooling system (Blythe 2002b, AFC §§ 1.5, 2.2.8, 2.2.8.2). The applicant predicts average water consumption of approximately 2,000 gallons per minute (gpm). Potable water will be provided by the water treatment system (Blythe 2002b, AFC §§ 2.2.8, 2.2.8.1, 2.2.8.5.2, Table 2.0-1, Table 2.0-2). Staff believes these sources yield sufficient likelihood of a reliable supply of water. (For further discussion of water supply, see the **Soil and Water Resources** section of this document.)

POWER PLANT RELIABILITY IN RELATION TO NATURAL HAZARDS

Natural forces can threaten the reliable operation of a power plant. High winds, flooding, tsunamis (tidal waves), and seiches (waves in inland bodies of water) will not likely represent a hazard for this project, but seismic shaking (earthquake) present credible threats to reliable operation.

Seismic Shaking

The site lies within Seismic Zone 3 (Blythe 2002b, AFC §§ 2.3.1, 7.16, 8.1.1, 8.1.2); see that portion of this document entitled **Geology, Mineral Resources, and Paleontology**. The project will be designed and constructed to the latest appropriate LORS (Blythe 2002b, AFC §§ 2.3.1, 8.1.2, Appendix 8.0). Compliance with current LORS applicable to seismic design represents an upgrading of performance during seismic shaking compared to older facilities, due to the fact that these LORS have been periodically and continually upgraded. By virtue of being built to the latest seismic design LORS, this project will likely perform at least as well as, and perhaps better than, existing plants in the electric power system. Staff has proposed conditions of certification to ensure this; see that portion of this document entitled **Facility Design**. In light of the historical performance of California power plants and the electrical system in seismic events, staff believes there is no special concern with power plant functional reliability affecting the electric system's reliability due to seismic events.

COMPARISON WITH EXISTING FACILITIES

Industry statistics for availability factors (as well as many other related reliability data) are kept by the North American Electric Reliability Council (NERC). NERC continually polls utility companies throughout the North American continent on project reliability data through its Generating Availability Data System (GADS), and periodically summarizes and publishes the statistics on the Internet (http://www.nerc.com). NERC reports the following summary generating unit statistic for the years 1997 through 2001 (NERC 2003):

For Combined Cycle units (All MW sizes)

Availability Factor = 90.31 percent

The gas turbines that will be employed in the project have been on the market for several years now, and can be expected to exhibit typically high availability. The applicant's prediction of an annual availability factor in the 92 to 98 percent range (Blythe 2002b, AFC § 8.3.2) appears reasonable compared to the NERC figure for similar plants throughout North America (see above). In fact, these new, large machines can well be expected to outperform the fleet of various (mostly older and smaller) gas turbines that make up the NERC statistics. Further, since the plant will consist of two parallel gas turbine generating trains, maintenance can be scheduled during those times of year when the full plant output is not required to meet market demand, typical of industry standard maintenance procedures. The applicant's estimate of plant availability therefore appears realistic. The stated procedures for assuring design, procurement and construction of a reliable power plant appear to be in keeping with industry norms, and staff believes they are likely to yield an adequately reliable plant.

FACILITY CLOSURE

Closure of the facility, whether planned or unplanned, will not impact power plant reliability. Reliability impacts on the electric system from facility closure, should there be any, are discussed in the **Transmission System Engineering** section of this document.

CONCLUSION

Blythe Energy predicts an equivalent availability factor in the 92 to 98 percent range, which staff believes is achievable in light of the industry norm of 90.31 percent for this type of plant. Based on a review of the proposal, staff concludes that the plant will be built and operated in a manner consistent with industry norms for reliable operation. This should provide an adequate level of reliability. No Conditions of Certification are proposed.

REFERENCES

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McGraw-Hill (McGraw-Hill Energy Information Services Group). 1994. *Operational Experience in Competitive Electric Generation, an Executive Report*, 1994.

NERC (North American Electric Reliability Council). 2003. <u>1997-2001 Generating Availability Report</u>.

TRANSMISSION SYSTEM ENGINEERING

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SUMMARY OF CONCLUSIONS

The current System Impact Study (SIS), considered as a screening and feasibility study, is incomplete and the study results are preliminary. As such the SIS does not comply with NERC/WECC, NERC and Cal-ISO standards. It will, therefore, be necessary for the applicant to submit a new SIS that would include a Power Flow study under 2006 summer peak and 2006 spring conditions, a Transient Stability study and a Short Circuit study and to address staff's concerns as stated in this staff assessment. The applicant has indicated that Southern California Edison (SCE), Western Area Power Administration (Western) and Imperial Irrigation District (IID) would perform the new SISs with actual details of the project interconnection facilities and the new transmission line before staff's final assessment. The information required before staff can complete the final assessment is listed in Conclusions and Recommendations.

To facilitate adequate transmission capacity to load centers for power flow from BEP II generation or for the combined generation of BEP I and BEP II, the applicant has identified a new 500 kV, 118-mile Desert Southwest Transmission line project (DSWTP) from Western's Buck Blvd Substation to SCE's Devers Substation (See TSE Figures 1-3, attached) that is under consideration to be built by IID as the project's primary transmission service. This is the only configuration staff is assessing in detail as it is the configuration the applicant has requested the Commission to permit. However, staff has insufficient information from the applicant or IID about the status of building the DSWTP and its expected completion date. Staff is not also aware whether IID has filed a "request to terminate" to Western and SCE, which would initiate the process for termination of the proposed new line to the SCE and Western systems. Also staff has received insufficient information from the applicant, SCE and Western about specific details of the new and/or modified facilities involved in the SCE and Western Substations to accommodate the new line. Staff, therefore, concludes that the feasibility of building the new line in a timely manner before the projected on-line date of the Blythe Energy Project Phase II (BEP II) remains uncertain at this stage and consequently the feasibility of the BEP II project also remains uncertain.

Since the diagrams submitted by the applicant do not reveal specific details of the proposed new and modified installations (See TSE Figures 3-5, attached), a full layout plan and description of the interconnecting facilities, including the new 500 kV line from the Buck Blvd 500 kV Substation to SCE's Devers Substation and any other required facilities are required after full evaluation of the new transmission facilities by Western and SCE.

INTRODUCTION

The Transmission System Engineering (TSE) analysis examines whether or not the transmission facilities associated with the proposed project conform to all applicable laws, ordinances, regulations and standards (LORS) required for safe and reliable electric power transmission, and assesses whether or not the applicant has accurately identified all interconnection facilities required for addition of the project to the electric grid.

Staff's analysis evaluates the power plant Switchyard, outlet line, termination and downstream facilities identified by the applicant and the staff. Staff's analysis provides proposed conditions of certification to ensure the project complies with applicable LORS during the design review, construction, operation and potential closure of the project.

Unlike other applications for certification, since the Western system is not a part of the California Independent System Operator (Cal-ISO) grid, the Cal-ISO is not directly responsible for ensuring electric system reliability for the generator interconnection to the Western System. The staff, therefore, has increased responsibility to evaluate the system reliability impacts of the project, and provide conclusions and recommendations to the Commission. However, the Cal-ISO has the responsibility for ensuring delivery of power to SCE's Devers Substation through the proposed new 500 kV line from Western's Buck Blvd Substation due to the addition of BEP II, for identifying reliability impacts of the project for all participating transmission owning utilities (SCE and SDG&E) and the feasibility of the required mitigation measures. The Cal-ISO will, therefore, provide their analysis and conclusions prior to staff's final assessment.

Additionally, under the California Environmental Quality Act (CEQA), the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). Therefore, the Energy Commission must identify and evaluate the environmental effects of construction and operation of any new or modified transmission facilities required for the project's interconnection to the electric grid, as well as any facilities beyond the project's interconnection with the existing transmission system that are required as a result of the power plant addition to the California transmission system.

Caithness Blythe II, LLC (applicant) filed an Application for Certification to the California Energy Commission to construct a nominal 520-megawatt (MW) natural gas-fired combined cycle generating facility to be located about 5 miles west of the City of Blythe near Interstate 10 and the Blythe Airport (BEP II, 2002a. Application for Certification, 2-20-02). The applicant proposes to connect their BEP II project to Western's existing Buck Blvd Substation where the Blythe Energy project Phase I (BEP I) presently is interconnected. According to the applicant, BEP II is expected to be on-line in the summer of 2006 (BEP II, 2002h).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

California Public Utilities Commission (CPUC) General Order 95 (GO-95), "Rules for Overhead Electric Line Construction," formulates uniform requirements for construction of overhead lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance and operation or use of overhead electric lines and to the public in general.

Western “General Requirements for Interconnection,” September 1999, provides Western’s general minimum requirements including technical, environmental and contractual requirements for interconnection, additions and modifications to Western’s transmission facilities.

The National Electric Safety Code, 1999 provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation.

The Western Electricity Coordinating Council (WECC) Planning Standards are merged with the North American Electric Reliability Council (NERC) Planning Standards and provide the system performance standards used in assessing the reliability of the interconnected system. Certain aspects of the NERC/WECC standards are either more stringent or more specific than the NERC standards alone. These standards provide planning for electric systems so as to withstand the more probable forced and maintenance outage system contingencies at projected customer demand and anticipated electricity transfer levels, while continuing to operate reliably within equipment and electric system thermal, voltage and stability limits. These standards include the reliability criteria for system adequacy and security, system modeling data requirements, system protection and control, and system restoration. Analysis of the WECC system is based to a large degree on Section I.A of the standards, “NERC and WECC Planning Standards with Table I and WECC Disturbance-Performance Table” and on Section I.D, “NERC and WECC Standards for Voltage support and Reactive Power”. These standards require that the results of power flow and stability simulations verify defined performance levels. Performance levels are defined by specifying the allowable variations in thermal loading, voltage and frequency, and loss of load that may occur on systems during various disturbances. Performance levels range from no significant adverse effects inside and outside a system area during a minor disturbance (loss of load or a single transmission element out of service) to a level that seeks to prevent system cascading and the subsequent blackout of islanded areas during a major disturbance (such as loss of multiple 500 kV lines along a common right of way, and/or multiple generators). While controlled loss of generation or load or system separation is permitted in certain circumstances, their uncontrolled loss is not permitted (WECC 2001).

NERC Planning Standards provide national policies, standards, principles and guidelines to assure the adequacy and security of the electric transmission system. The NERC planning standards provide for system performance levels under normal and contingency conditions. With regard to power flow and stability simulations, while these Planning Standards are similar to NERC/WECC Standards, certain aspects of the WECC standards are either more stringent or more specific than the NERC standards for Transmission System Contingency Performance. The NERC planning standards apply to interconnected systems and to individual service areas (NERC 1998).

Cal-ISO Planning Standards also provide standards, and guidelines to assure the adequacy, security and reliability in the planning of the Cal-ISO transmission grid facilities. The Cal-ISO Planning Standards incorporate the merged NERC and WECC Planning Standards. With regard to power flow and stability simulations, the Cal-ISO Planning Standards are similar to NERC/WECC and the NERC Planning Standards for Transmission System Contingency Performance. However, the Cal-ISO Standards also provide some additional requirements that are not found in the NERC/WECC or NERC Planning Standards. The Cal-ISO Standards apply to all participating transmission owners interconnecting to the Cal-ISO controlled grid. It also applies when there are any impacts to the Cal-ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the Cal-ISO (Cal-ISO 2002a).

EXISTING FACILITIES AND RELATED SYSTEMS

The existing transmission facilities in the vicinity of the BEP II project area include (See TSE Figure BART.1, attached):

- Buck Boulevard 161/230 kV Substation. This Western Substation is located about 2000 feet northeast of the project site.
- Blythe 161 kV Substation. This Western Substation is connected to the Buck Boulevard 161/230 kV Substation by an 1800 feet 161 kV single circuit line.
- Palo Verde-Devers 500 kV line owned by Southern California Edison (SCE).
- Parker-Gene 230 kV line owned by Western.
- Gene-Camino-Eagle Mountain-Julian Hinds-Devers 230 kV line owned by MWD (Metropolitan Water District) and operated by SCE.
- Parker-Harcuvar-Hassyampa 230 kV line owned by Bureau of Reclamation (BOR) and operated by Western.

The Blythe Substation which is a part of Western's "South of Parker" transmission system, is connected with the following 161 kV lines:

1. Blythe-Knob 161 kV line owned by Western.
2. Parker-Blythe 161 kV line owned by Western.
3. Parker-Headgate-Blythe 161 kV line owned by Western.
4. Niland-Blythe 161 kV line owned by Imperial Irrigation District (IID).
5. Eagle Mountain-Blythe 161 kV line owned by SCE.

Western's Blythe and Parker Substations receive significant hydropower from Western's Hoover, Davis and Parker Dams, and transmit power to Arizona and lower Colorado River areas served by IID and Arizona Public Service (APS). In view of limited transmission capacity in the "South of Parker" transmission system and in the existing Palo Verde-Devers 500 kV line, accommodating power output from the BEP II would require a new bulk 230 or 500 kV transmission line to load centers like the proposed DSWTP from Blythe to Devers Substation or a second Palo Verde-Devers 500 kV line via Blythe.

PROJECT DESCRIPTION

The BEP II site would be located approximately 2000 feet southwest of the Western Buck Boulevard 161/230 kV Substation. The BEP II would consist of two combustion turbine generators (CTG), each with an output of approximately 170 MW and one 180 MW steam turbine generator (STG), for a total plant nominal output of 520 MW. Each of the generating units would be connected to a dedicated 225 MVA, 16/500 kV step-up transformer and the high voltage terminals of each transformer would be connected to the new BEP II 500 kV Integration Switchyard switch bays by overhead conductors (See TSE Figures 2 & 5, attached).

BEP II Integration Switchyard

The new BEP II 500 kV Integration Switchyard would have four switch bays with 500 kV circuit breakers. The high voltage transformer terminals of two CTG and one STG units would be connected by overhead conductors to three switch bays. The fourth bay would be connected to a 500 kV 2-2156 ACSR interconnecting line to a new 500 kV Substation to be built as an expansion of the existing Buck Blvd. Substation within its fence line. The applicant would build, own and operate the BEP II Integration Switchyard (See TSE Figures 2 & 5, attached).

Transmission Interconnection Facilities and Buck Boulevard 500 kV Substation

The new BEP II 500 kV Integration Switchyard is proposed to be interconnected to the new Western Buck Blvd 500 kV Substation by building an approximately 2500 feet new 2-2156 ACSR 500 kV transmission line, which would carry the full generation output of the BEP II. The new Buck Blvd 500 kV Substation would have three switch bays with 500 kV circuit breakers. The proposed 500 kV substation would be connected to the existing Buck Blvd 161/230 kV Substation by installing a 400 MVA 500/230/161 kV step-down dual voltage transformer in the new substation. The third 500 kV switch bay would be used to connect the new 118-mile 500 kV line to SCE's Devers Substation (See TSE Figures 2-4, attached). Western has not yet confirmed the layout plan for interconnecting facilities at the Buck Blvd Substation and staff's description is, therefore, preliminary.

New 500 kV Transmission Line

To facilitate adequate transmission capacity to load centers for additional power flow from BEP II generation output or from the combined generation output from both BEP I and BEP II, building a new 118-mile 500 kV line with 2-2156 ACSR conductor from the proposed Western Buck Blvd 500 kV Substation to SCE's Devers 500 kV Substation is under consideration by a third party (IID and/or others) and it would serve as the project's primary transmission service (See TSE Figures 1-3, attached). No information has been received by the staff directly from SCE or Western about the specific details of the new facilities and/or modifications involved in the SCE and Western Substations to accommodate the new line.

IID and the Bureau of Land Management (BLM) jointly are pursuing an EIS/EIR with various options and routes of a proposed Desert Southwest Transmission Project (DSWTP). The project includes a 118-mile 230 kV double circuit or 500 kV single circuit line (BEP II, 2003g. Draft Environmental Impact Statement/Environmental Impact

Report (EIS/EIR), 03-25-03). According to the EIS/EIR the line would start from a new IID Hobsonway 230 or 500 kV Substation near the BEP II project and terminate at SCE's Devers 500/230 kV Substation and it could loop into IID's Coachella or Dillon Road 230 or 500 kV Substation before terminating at the Devers 500/230 kV Substation. Staff has been advised by the applicant that a Hobsonway substation is no longer proposed. Staff has received insufficient information from the applicant or IID to confirm that IID has applied to Western and SCE for termination of the proposed line to the Western or SCE system. Also, the configuration of the IID proposal has not been verified by the IID or the BLM.

ANALYSIS AND IMPACTS

SYSTEM RELIABILITY

A System Impact Study (SIS) for connecting a new power plant to the existing power system grid is performed to determine the required transmission facilities to interconnect the plant to the grid, downstream transmission system impacts, and their mitigation measures in conformance with system performance levels as required in Utility reliability criteria, NERC planning standards, NERC/WECC reliability criteria and Cal-ISO reliability criteria. The study determines both positive and negative impacts, and for the reliability criteria violations (for the negative impacts) determines the alternate and preferred additional transmission facilities or other mitigation measures. The study is conducted with and without the new generation project and its interconnection facilities by using the computer model base case for the year the generator project would come on-line. The study normally includes a Load Flow study, Transient Stability study, Post-transient Load Flow study and Short Circuit study. The study is focused on thermal overloads, voltage deviations, system stability (excessive oscillations in the generators and transmission system, voltage collapse, loss of loads or cascading outages) and short circuit duties. The study must be conducted under normal conditions (N-0) of the system (see Definition of Terms) and also for all credible contingency/emergency conditions, which include the loss of a single system element (N-1) such as a transmission line, transformer or a generator and the simultaneous loss of two system elements (N-2), such as two transmission lines or a transmission line and a generator. The study may also be conducted for credible simultaneous loss of multiple (more than two) system elements. In addition to the above analysis, studies may be performed to verify whether sufficient active or reactive power margins are available in the area system or area sub-system to which the new generator project would be interconnected. The SIS is followed by supplemental studies conducted by the transmission owner with details provided in a Detailed Interconnection Facility Study (DIFS) or a Facility Cost Report (FCR).

System Impact Study (SIS)

The CEC staff initiated a workshop to help the applicant to prepare a computer model of the base case on September 10, 2002 in Ontario, CA. The workshop was attended by the CEC staff, the applicant and their representatives, the representatives of affected transmission stakeholders (SCE, Western, MWD, IID, SDG&E (San Diego Gas & Electric) and others (Arizona Public Service (APS), Salt River Project (SRP)) in order to build a consensus in preparation of a system Computer model base case for 2006 summer peak and light spring conditions. Accordingly, a 2006 summer peak pre-project base case was

developed by K. R. Saline and associates from the WECC 06HS2SA base case published by WECC in June, 2002. The base case was reviewed by the transmission owners and modified with respect to transmission path flows, loads and generation in the affected areas to suit the requirement of the study. Subsequently, a 2006 spring pre-project base case was developed by K. R. Saline and Associates from the 2006 summer peak pre-project base case by reducing loads and generation in the SCE system and loads in the IID system.
The following system Impact studies for screening and feasibility of alternative interconnections of the project have so far been received from the applicant:

1. Blythe Energy project II-Technical Assessment dated March 6, 2002 conducted by SCE (BEP II, 2002c). The study was performed under 2004 Summer peak and 2004 Light Spring system conditions with BEP II connected to Buck Blvd 230 kV Substation with BEP I and a double circuit 80-mile 230 kV new line modeled between Buck Blvd Substation and IID's Midway 230 kV Substation, and a 20-mile 230 kV new line from IID's El Centro switching station to High Line Substation.

2. BART (Blythe Area Regional Transmission) Study dated October 22, 2002 performed by K. R. Saline and Associates (BEP II, 2002h). The study was performed under 2006 Summer peak condition. The study considered three 230 kV new transmission option scenarios with radial connection from BEP II Switchyard, a double circuit 80-mile 230 kV new line from BEP II Switchyard to IID's Midway 230 kV Substation with or without a 20-mile 230 kV new line from IID's El Centro switching station to High Line Substation, a double circuit 120-mile 230 kV new line between BEP II Switchyard and SCE's Devers Substation.

3. BART Study dated February, 2003 performed by K. R. Saline and Associates (BEP II, 2003b). The study was performed under 2006 summer peak condition. The study considered two new transmission options, a double circuit 120-mile 230 kV line or a single circuit 120-mile 500 kV line between Buck Blvd Substation and SCE's Devers Substation with a short line between BEP II Switchyard and Buck Blvd Substation, and BEP II remains connected radial to Devers Substation.

4. BART Study dated March 7, 2003 performed by K. R. Saline and Associates (BEP II, 2003c). The study was performed under 2006 summer peak condition. The study considered four new transmission options with radial connection from BEP II Switchyard, a double circuit 80-mile new line from BEP II Switchyard to IID's Midway 230 kV Substation with or without a 20-mile 230 kV new line from IID's El Centro switching station to High Line Substation, a double circuit 120-mile 230 kV line or a single circuit 120-mile 500 kV line between BEP II Switchyard and SCE's Devers Substation.

5. BART Studies dated July 7 (BEP II, 2003h) & dated August 14, 2003 (BEP II, 2003f) performed by K. R. Saline and Associates The Study was performed under 2006 summer peak and 2006 spring conditions. In the summer peak base case, the interconnection facilities were not modeled according to the selected project configuration. The Study modeled the project interconnection facilities and the new transmission line (Bart SC4 base case) for the summer peak case as follows:

a. BEP II 500 kV and 230 kV Switchyards (BEP II units connected to BEP II 230 kV Switchyard bus) with a new short 230 kV interconnecting line between BEP II 230 kV switchyard and Buck Blvd 230 kV Substation, and with two units of BEP I connected to Buck Blvd Substation 230 kV Bus and one unit of BEP I connected to Buck Blvd Substation 161 kV Bus.

b. A 500/230 kV transformer bank at the BEP II Switchyard.

c. A new 120-mile 500 kV line with 2-2156 ACSR conductor from the BEP II 500 kV Switchyard to SCE's Devers 500/230 kV Substation.

The study for spring case modeled the project interconnection facilities and the new transmission line (Bart SC4 spring base case) as the selected project description above to CEC requirements.

Scope of the Current SIS

The August 14, 2003 study is now considered by the applicant as a feasibility study in support of BEP II generator interconnection and the new bulk 500 kV transmission line capacity (BEP II, 2003f).

The August 14, 2003 study modeled the BEP II project for a net output of 520 MW. The Power Flow studies were conducted by K. R. Saline and Associates with and without BEP II with the interconnection facilities and the new 500 kV transmission line as above for a 2006 summer peak and a 2006 spring system conditions under normal (N-0), single (N-1) and credible double contingency (N-2) conditions. The spring study post-project base case was modeled according to the project configuration as described above, but the summer study post-project base case was not modeled according to the project configuration, but modeled with many approximations. The base cases modeled transmission system Path Flows (East of the River (EOR), Path 42, Path 59 and Path 45), included all anticipated transmission projects through summer of 2006 and new generation projects with a scheduled completion or on-line date before the expected on-line date of the BEP II.

The conclusions contained herein apply to the study results submitted.
The results of the analysis provide only a preliminary assessment of the overloads that violate reliability criteria under normal and contingency conditions of the system.

Power Flow Study Results

Based on the study dated August 14, 2003 results, there are some adverse impacts following certain outages on the electrical grid due to interconnection of the BEP II as proposed. A summary of the overload violations under 2006 summer peak and spring conditions has been provided in Tables SC4.0, SC4.1, SC4.2, SC4.0 Spring, SC4.1 Spring and SC4.2 Spring of the study report (BEP II 2003f).

Normal (N-0) Conditions

There are no new overload violations identified during normal conditions due to the addition of the BEP II under 2006 summer peak conditions. However, under 2006 spring normal conditions, a new overload criteria violation[1] due to the addition of BEP II is identified as follows:

1. The loading of the Imperial Valley-Miguel 500 kV line increases from 99 percent to 101.1 percent of its normal rating.

Two pre-project existing overloads increased by BEP II under 2006 summer peak normal conditions are identified as follows:

1. The loading of Rainbow 230 kV phase shifting transformer increases from 128 to 129 percent of its normal rating.
2. The loading of Mead-Big Sandy 500 kV line increases from 111.7 to 112.8 percent of its normal rating.

Under 2006 spring normal conditions, three pre-project existing overloads increased by BEP II are identified as follows:

1. The loading of the Rainbow 230 kV phase shifting transformer increases from 130 to 132 percent of its normal rating.
2. The loading of the Mead-Big Sandy 500 kV line increases from 112.1 to 113.5 percent of its normal rating.
3. The loading of the Miguel 500/230 kV transformer increases from 109 to 111 percent of its normal rating.

Single Contingency (N-1) Conditions

One new emergency overload violation is identified under 2006 summer peak conditions for single contingencies (N -1) as follows:

1. The Devers 500/230 kV transformer is found overloaded due to outage of the Devers-Valley 500 kV line and the transformer loading increases from 98.3 percent to 123.8 percent of its emergency rating.

Two new emergency overload violations are identified under 2006 spring conditions for single contingencies (N -1) as follows:

1. The Devers 500/230 kV transformer is found overloaded due to outage of the Devers-Valley 500 kV line and the transformer loading increases from 85.4 percent to 137.2 percent of its emergency rating.
2. The Devers-San Bernardino 230 kV line #1 is overloaded due to outage of the Devers-Valley 500 kV line and the line loading increases from 88.1 percent to 109.6 percent of its emergency rating.

Two pre-project existing overloads increased by BEP II are identified under 2006 spring conditions for single contingencies as follows:

[1] Any loading in a facility above 100 percent of its capacity is considered a criteria violation and becomes a potential problem.

1. The Rainbow 230 kV phase shifting transformer is overloaded due to outage of the Imperial Valley-Miguel 500 kV line and the transformer loading increases from 100.5 percent to 102.9 percent of its emergency rating.
2. The Roa-Rum 230 kV line is overloaded due to outage of the Imperial Valley-Miguel 500 kV line and the line loading increases from 115 percent to 116.3 percent of its emergency rating.

Notes:

1. Under 2006 summer peak conditions, staff's preliminary power flow analysis[2] with available information shows that upon outage of the Blythe–Buck Blvd 161 kV line, about 1021 MW power flow to Devers Substation from the BEP I & BEP II units does not cause any overload in the Devers Substation or the lines connected to the Devers Substation.
2. Under 2006 summer peak conditions, staff's preliminary analysis[2] with available information shows that upon outage of the new 500 kV line between Devers and the BEP II 500 kV Switchyard and with all units of the BEP I & BEP II on-line, overloads were identified in the interconnecting facilities between the BEP II 230 kV Switchyard and the Buck Blvd 230 kV Substation (135 percent), and between the Buck Blvd 230 kV Substation and the Blythe Substation (148 percent in each 230/161 kV transformer), and in the Blythe- Niland (148 percent) and Blythe-Blythe SC-Eagle Mountain (134 percent) 161 kV lines based on their emergency ratings.

Double Contingency (N-2) Conditions

There are no new overload violations identified for selected credible double contingencies due to addition of the BEP II under 2006 summer peak and 2006 spring conditions.

However, one pre-project existing overload increased by BEP II during double contingencies under both 2006 summer peak and 2006 spring conditions was identified as follows:

1. The Niland-Midway 161 kV line is overloaded due to outages of the Coachella-Miday 230 kV lines #1 & 2. Under 2006 summer peak conditions, the line loading increases from 163.7 percent to 173.4 percent of its emergency rating. Under 2006 spring conditions, the line loading increases from 168.6 percent to 184.5 percent of its emergency rating.

Mitigation of Overloaded Facilities and Comments

To offset most of the identified new or existing pre-project overload violations due to addition of BEP II, the applicant is apparently selecting to trip adequate generation from BEP II without any concurrence with the respective transmission owners of the overloaded facilities and/or Cal-ISO. Staff requested the applicant per CEC Data

[2] Staff modified the modeling of the summer BART SC4 base case for 1) the 500/230 kV 3-winding transformer at the BEP II Switchyard, 2) the new 500 kV line from the BEP II Switchyard to Devers substation, and 3) with all three BEP I units connected to the Buck Blvd substation 230 kV bus.

Request number 227e dated May, 2003, to provide a letter or a report from the respective transmission owner and, where applicable, from the Cal-ISO verifying the rationale and feasibility of the mitigation measure and its implementation for each criteria violation prior to the on-line date of the BEP II plant. This information is expected to be received with the new SISs of Western, SCE and IID in 3-6 months.

The study report has discussed mitigation considerations for overloading of the Devers 500/230 kV transformer for outage of the Devers-Valley 500 kV line. The mitigation alternatives considered by the applicant are tripping adequate generation from the BEP II or installing a second 500/230 kV transformer at Devers Substation.

For overloading of Devers-San Bernardino 230 kV line #1 due to outage of the Devers-Valley 500 kV line, development of a "Devers Import Nomogram" with respect to power flows from various lines and loads at Devers Substation under different scenarios is suggested by the applicant as mitigation. Under 2006 summer peak conditions, staff's preliminary analysis with available information shows that due to outage of the Blythe–Buck Blvd 161 kV line, about 1021 MW power flow to Devers Substation from BEP I & BEP II units does not cause any overload in the Devers Substation and the 230 kV lines connected to the Devers Substation. Staff recommends that this contingency should be restudied in the new SIS.

In the summary of conclusions, the report suggested that for critical outage of the new 500 kV line from Buck Blvd Substation to Devers, a RAS (Remedial Action Scheme) would be required to trip all the units of BEP II so that the power flow to Blythe Substation from Buck Blvd Substation would be limited to 520 MW (BEP I Units). However, no contingency study was found in support of the conclusion. Under 2006 summer conditions, staff's preliminary analysis with available information shows that due to outage of the new 500 kV line between Devers and BEP II Switchyard and with the BEP I & BEP II all units on-line, overloads would happen in the interconnecting facilities between the BEP II Switchyard and the Buck Blvd Substation, and between the Buck Blvd Substation and the Blythe Substation, and in the Blythe- Niland and Blythe-Blythe SC-Eagle Mountain 161 kV lines. To offset the overloads based on available information and emergency ratings of the transmission elements, it appears that tripping two units of BEP II or BEP I generation would be necessary instead of all the three units of BEP II as suggested. Staff recommends that this contingency analysis should be restudied in the new SIS to arrive at a mitigation measure.

The present report by the applicant suggests that the applicant will discuss mitigation measures with the respective transmission owners and then incorporate selected mitigation measures in the new System Impact Study report.

Transient Stability Study

The applicant has not submitted a Dynamic Stability Study report. The staff requested the applicant to submit the study report covering SCE, Western, IID and SDG&E systems per CEC Data Request number 228 dated May 2003. The applicant responded that the analysis would be submitted with the new System Impact study prior to the final staff assessment.

Short Circuit Study

The applicant has not submitted a Short Circuit Study report. The staff requested the applicant to submit the study report covering SCE, Western, IID and SDG&E systems per CEC Data Request number 229 dated May, 2003. The applicant responded that the analysis would be submitted with the new System Impact study prior to the final staff assessment.

Comments on the Current SIS and Requirements for the New SIS

The applicant considered the August 14, 2003 study as a feasibility study and stated that it is not intended as a SIS. While staff concurs with the applicant that the purpose of the present study should be considered as a screening and feasibility study, staff observes the current SIS is incomplete and the study results are preliminary due to various reasons stated below.

The spring study post-project base case was modeled according to the project configuration as described above, but the summer study post-project base case was not modeled according to the project configuration, but modeled with approximations. Staff found modeling discrepancies in the following transmission elements of the 2006 post-project summer peak base case (Bart SC4 base case):

1. 500/230 kV step-up transformer at BEP II Switchyard with a tertiary winding.
2. 120 mile 500 kV line from BEP II Switchyard to Devers and its thermal rating.

In addition all 3 units of BEP I were not connected to the Buck Blvd 230 kV or 161 kV Substation bus per the present plan. After staff modified the modeling[3] with the information available, staff's preliminary analysis indicates that the power flow to Devers from the BEP II Switchyard would be about 822 MW instead of 730 MW as shown in Bart SC4 base case.

Similarly Staff found modeling discrepancies in the following transmission elements of the 2006 post-project summer peak base case (Bart SC4 CEC base case):

1. 500/230 /161 kV step-down transformer at Buck Blvd Substation.
2. 120 mile 500 kV line from BEP II Switchyard to Devers and its thermal rating.
3. 500 kV short interconnection line from BEP II Switchyard to Buck Blvd Substation.

After staff modified the modeling[4] with the information available, staff's preliminary analysis found that the power flow to Devers from Buck Blvd Substation would be about 818 MW instead of 730 MW as shown in Bart SC4 CEC case.

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[3] Staff modified the modeling of the summer BART SC4 base case for 1) the 500/230 kV 3-winding transformer at the BEP II Switchyard, 2) the new 500 kV line from the BEP II Switchyard to Devers substation, and 3) with all three BEP I units connected to the Buck Blvd substation 230 kV bus.

[4] Staff modified the modeling of the summer BART SC4 CEC base case for 1) the 500/230/161 kV transformer at the Buck Blvd. Substation, 2) the new 500 kV line from the Buck Blvd. Substation to Devers substation, and 3) the 500 kV short Interconnection line from the BEP II Switchyard to the Buck Blvd. Substation.

Staff believes that such discrepancies in modeling the new transmission elements for the interconnection of BEP II and their effects on the power flows result in a failure to identify realistic adverse impacts under normal and contingency conditions in the affected systems (SCE, IID, Western, San Diego Gas & Electric (SDG&E) and CFE (in Mexico)). Consequently, the study results would be affected and the selected mitigation measures could be wrong, ineffective or partially effective, and conformance with NERC/WECC, NERC, Western Interconnection and Cal-ISO Planning standards and reliability criteria would not be assured. After discussion with representatives of SCE and K. R. Saline & Associates, staff expects that the new SISs will be adequately modeled.

In the development of the 2006 pre-project spring base case, staff found that the 2006 summer peak pre-project base case was converted to spring case by reducing load and generation in the SCE system and by reducing loads in the IID system. Staff also observes that the current study results dated August 14, 2003 show more adverse impacts under spring conditions than under summer peak conditions. Staff, therefore, recommends that the 2006 spring base case development in the new SISs should be initiated from an original spring case published by WECC like the 2006 summer peak case and be further modified for study area systems to suit the requirement of the study. Staff believes that a study with such a spring case would provide more confident system impact results for power flow and for transient stability analyses. Staff also believes that a SIS under spring conditions in addition to summer peak conditions is essential to identify all adverse system impacts. After discussion with representatives of SCE and K. R. Saline and Associates, staff expects that the new system impact studies to be performed by SCE, Western and IID would focus on spring conditions with an appropriate base case as suggested above.

In the August 14, 2003 study report, power flow diagrams for the overload violations as discussed above or as mentioned in the tables of the report (except two violations) were not attached. Staff requested the applicant to submit such power flow diagrams per Data Request number 227 dated May 2003. Staff expects that the power flow diagrams for each overload violation would be furnished with the new SISs.

To mitigate most of the identified new or existing pre-project overload violations due to the addition of BEP II, the applicant is apparently selecting to trip sufficient generation from BEP II without any concurrence with the respective transmission owners of the overloaded facilities and/or Cal-ISO. Staff requested the applicant per CEC Data Requests number 227e dated May, 2003, to provide a letter or in the form of a report from the respective transmission owner and, where applicable, from the Cal-ISO verifying the rationale and feasibility of the mitigation measure and its implementation for each criteria violation prior to the on-line date of the BEP II plant. The present report by the applicant suggests that the applicant will discuss mitigation measures with the respective transmission owners and then incorporate selected mitigation measures in the new System Impact Study report.

The applicant has not submitted Dynamic Stability and Short Circuit analysis reports covering the affected SCE, Western, IID and SDG&E systems. Staff recommends that the Dynamic Stability study be conducted with a post-project spring base case as recommended above. Staff expects to receive the analyses with the new SISs.

In view of the above, CEC staff will need a new SIS from the applicant, which will include a Power Flow study under 2006 summer peak and spring conditions, a Dynamic Stability study and a Short Circuit study that would address staff's concerns as identified above. The applicant indicated that SCE, Western and IID would perform the new SISs and Facility studies before staff's final assessment.

Cal-ISO Review

Unlike other applications for certification, since the Western system is not a part of the California Independent System Operator (Cal-ISO) grid, the Cal-ISO is not directly responsible for ensuring electric system reliability for the generator interconnection in the Western System. However, the Cal-ISO has the responsibility for ensuring delivery of power to SCE's Devers Substation through the proposed new 500 kV line from Western's Buck Blvd Substation due to the addition of BEP II, for identifying reliability impacts of the project for all participating transmission owning utilities (SCE and SDG&E) and the feasibility of the required mitigation measures. In view of the current SIS being considered as a feasibility study, which is preliminary and subject to new studies by SCE, Western and IID, staff will request the Cal-ISO to review the new study reports, provide their analysis and conclusions before staff's final assessment.

The Cal-ISO's analysis of the new studies and concurrence with selected mitigation measures would assure conformance with NERC/WECC, NERC and Cal-ISO planning standards and reliability criteria for the Cal-ISO controlled grid.

NEW 500 KV TRANSMISSION LINE AND SYSTEM MODIFICATIONS

In addition to the BEP II Integration Switchyard and 500 kV interconnection transmission facilities to Western's Buck Blvd Substation as proposed by the applicant, the BART feasibility & screening study concludes that accommodating the power output of the BEP II will require a new bulk power transmission line to load centers due to the limited transmission capacity availability in the south of Parker Western system especially after interconnection of BEP I to the Buck Blvd Substation. The applicant has identified a new 500 kV, 118-mile Desert Southwest Transmission line project (DSWTP) from Western's Buck Blvd Substation to SCE's Devers Substation (See TSE Figures 1-3, attached) that is under consideration to be built by IID as the project's primary transmission service. This is the only configuration staff is assessing in detail as it is the configuration the applicant has requested the Commission to permit. However, staff has insufficient information from the applicant or IID about the status of building the DSWTP and its expected completion date. No information has been received by the staff directly from SCE or Western about the specific details of the new facilities and/or modifications involved in the SCE and Western Substations to accommodate the new line.

Upon interconnection of BEP II, Western may operate the Buck Blvd Substation at either 161 kV or 230 kV. If Western operates the Buck Blvd Substation at 230 kV, a 560 MVA 230/161 kV transformer will be installed in the Substation to feed the 161 kV line to the 161 kV Blythe Substation.

CUMULATIVE IMPACTS

In view of the proximity of BEP II with BEP I, the new transmission interconnections, new bulk transmission facilities, and considering the project's location in Western's "south of Parker" system, staff believes that the project would have some cumulative overload impacts on the interconnected systems especially in 500 and 230 kV networks of the SCE system. The cumulative impacts due to the BEP II should, however, be mitigated with the implementation of mitigation measures as would be selected in the new SISs and Facility studies.

ALTERNATIVE TRANSMISSION INTERCONNECTION FACILITIES

The applicant considered four transmission interconnection alternative options as follows (BEP II, 2003c):

1. Option 1: A double circuit 80-mile 230 kV line with 2-1272 ACSR conductor from BEP II 230 kV Switchyard to IID's Midway 230 kV Substation. The alternative also included a new 230 kV line with 2-1272 ACSR conductor from IID's Highline 230 kV Substation to El Centro Switching station.
2. Option 2: A double circuit 80-mile 230 kV line with 2-1272 ACSR conductor from BEP II 230 kV Switchyard to IID's Midway 230 kV Substation.
3. Option 3: A double circuit 120-mile 230 kV line with 2-2156 ACSR conductor from BEP II 230 kV Switchyard to SCE's Devers 500/230 kV Substation.
4. Option 4: A 120-mile 500 kV line with 2-2156 ACSR conductor from BEP II 500 kV Switchyard to SCE's Devers 500/230 kV Substation.

These interconnection alternatives when compared to the preferred one (A 118-mile 500 kV line with 2-2156 ACSR conductor from Buck Blvd. 500 kV Substation to SCE's Devers 500/230 kV Substation, a 500 kV interconnection line from BEP II 500 kV Switchyard to the new Buck Blvd 500 kV Substation with a 500/230/161 kV step-down transformer at the new Buck Blvd 500 kV Substation), were not chosen by the applicant on the basis of the BART feasibility and screening system studies (BEP II, 2003f). While all the interconnection alternatives are feasible, staff considers the selected option acceptable.

COMPLIANCE WITH LORS

Staff concludes that the SIS submitted does not comply at this stage with NERC/WECC, NERC and Cal-ISO standards due to the various reasons stated above.
The proposed BEP II Integration Switchyard would be located within the fenced yard of the project site. The applicant would design, build, own and operate the proposed substation. The proposed overhead 500 kV interconnection line to be built by Western or the applicant between the BEP II 500 kV Switchyard and the Buck Blvd 500 kV Substation would be located along a proposed right of way to be provided by current land owners. Western would design, build and operate the new Buck Blvd 500 kV Substation, 400 MVA, 500/230/161 kV step-down transformer and 560 MVA, 230/161 kV step-down transformer, which would be located within the fenced yard of the existing Buck Blvd Substation (See TSE Figures 1-2, attached). Since the diagrams submitted

by the applicant do not reveal specific details of the proposed new and modified installations, a full layout plan and description of the interconnecting facilities, including the new 500 kV line from Buck Blvd 500 kV Substation to SCE's Devers Substation and any other facilities beyond the point where the outlet line joins with the interconnected system, are required (See TSE Figures 3-5, attached).

FACILITY CLOSURE

PLANNED CLOSURE

A planned closure occurs in an orderly manner such as at the end of its useful economic or mechanical life or due to gradual obsolescence. Under such circumstances, the owner is required to provide a closure plan 12 months prior to closure, that in conjunction with applicable LORS, is considered sufficient to provide adequately for safety and reliability. For instance, a planned closure provides time for the owner to coordinate with the Transmission Owner (TO), in this case PG&E, to assure (as one example) that the TO's system would not be closed into the outlet thus energizing the project substation. Alternatively, the owner may coordinate with the TO to maintain some power service via the outlet line to supply critical station service equipment or other loads.

UNEXPECTED TEMPORARY CLOSURE

An unplanned closure occurs when the facility is closed suddenly and/or unexpectedly for a short term due to unforeseen circumstances such as a natural or other disaster or emergency. During such a closure the facility cannot insert power into the utility system. Closures of this sort can be accommodated by establishing an on-site contingency plan (see **General Conditions Including Compliance Monitoring and Closure Plan**).

Unexpected Permanent Closure

This unplanned closure occurs when the project owner abandons the facility. This is considered to be a permanent closure. This includes unexpected closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unexpected closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned. An on-site contingency plan, that is in place and approved by the Energy Commission's Compliance Project Manager (CPM) prior to the beginning of commercial operation of the facilities, would be developed to assure safety and reliability (see **General Conditions Including Compliance Monitoring and Closure Plan**).

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No agency or public comments related to the TSE discipline have been received.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes as follows:

1. The current SIS, considered as a screening and feasibility study, is incomplete and the study results are preliminary. Due to modeling discrepancies and approximations of the BEP II project interconnection facilities and the new bulk transmission line, and without a proper spring base case, staff is not confident that the Power Flow study results have identified all system reliability criteria violations and their degree of impacts in the affected systems of SCE, IID, SDG&E and Western. In addition the applicant has not submitted the study reports for a Transient Stability and a Short Circuit analyses and as such the system impacts in these analyses are unknown. It will, therefore, be necessary for the applicant to submit a new SIS that would include a Power Flow study under 2006 summer peak and 2006 spring conditions, a Transient Stability study and a Short Circuit study that would address staff's concerns as above. The applicant has indicated that SCE, Western and IID would perform the new SISs with actual details of the project interconnection facilities and the new transmission line before staff's final assessment.
2. To mitigate most of the identified new or existing pre-project overload violations due to the addition of BEP II, the applicant is apparently selecting to trip sufficient generation from BEP II without the concurrence of the respective transmission owners of the overloaded facilities and/or Cal-ISO. Staff requested the applicant in CEC Data Requests dated May, 2003, to provide a letter or a report from the respective transmission owner and, where applicable, from the Cal-ISO verifying the rationale and feasibility of the mitigation measure and its implementation for each criteria violation prior to the on-line date of the BEP II plant. The report dated August 14, 2003 by the applicant suggests that the applicant will discuss mitigation measures with the respective transmission owners and then incorporate selected mitigation measures in the new System Impact Study report.
3. The SIS concludes that BEP II can be interconnected to the electrical grid at Western Buck Blvd Substation, but delivering the power output of the BEP II and BEP I, will require a new bulk power transmission line from Buck Blvd Substation or BEP II Switchyard to Devers or other load centers due to limited transmission capacity availability in the "South of Parker" Western system especially after interconnection of BEP I to Buck Blvd Substation. To facilitate adequate transmission capacity for additional power flow from the BEP II generation or for the combined generation of BEP I and BEP II, the applicant has identified a new 500 kV, 118-mile Desert Southwest transmission line project (DSWTP) from Western's Buck Blvd Substation to SCE's Devers Substation, that is under consideration to be built by IID as the project's primary transmission service. However, staff has insufficient information from the applicant or IID about status of building the DSWTP and its expected completion date. Staff is also not aware whether IID has filed any "request to terminate" to Western and SCE, which would initiate the process for terminating the proposed new line to SCE and Western systems. Also staff has received insufficient information from the applicant or SCE or Western about specific details of the new and/or modified facilities involved in the SCE and

Western Substations to accommodate the new line. Therefore, the feasibility of building the new line in a timely manner before the projected on-line date of BEP II remains uncertain at this stage and consequently the feasibility of the BEP II project also remains uncertain.

4. Since the diagrams submitted by the applicant do not reveal specific details of the proposed new and modified installations, a full layout plan and description of the interconnecting facilities, including the new 500 kV line from Buck Blvd 500 kV Substation to SCE' Devers Substation and any other facilities beyond the point where the outlet line joins with the interconnected system, are required.

5. Since the Western system is not a part of the California Independent System Operator (Cal-ISO) grid, the Cal-ISO is not directly responsible for ensuring electric system reliability for the generator interconnection to the Western System. However, the Cal-ISO has the responsibility for ensuring delivery of power to SCE's (Southern California Edison) Devers Substation through the proposed new 500 kV line from Western's Buck Blvd Substation due to the addition of BEP II, for identifying reliability impacts of the project for all participating transmission owning utilities (SCE and SDG&E) and the feasibility of the mitigation measures. In view of the present SIS being considered as a feasibility study which is preliminary and subject to new studies by SCE, Western and IID, the Cal-ISO will review the new study reports and provide their analysis before staff's final assessment. The Cal-ISO's analysis and concurrence with selected mitigation measures would assure conformance with NERC/WECC, NERC and Cal-ISO planning standards and reliability criteria for the Cal-ISO controlled grid.

6. Because staff's standard conditions are not sufficient to remedy the preliminary nature of the System Impact studies and because staff can not confidently identify the project facilities, no Conditions of Certification are recommended at this stage. Staff will provide recommended Conditions of Certification in the final staff assessment subject to receipt of adequate System Impact studies.

In order for the staff to complete the Final Staff Assessment, the following information is needed:

1. The System Impact Study (SIS) and/or Facility study (FS) to be performed by SCE would include a Power Flow study under 2006 summer peak and 2006 spring conditions, a Transient Stability study and a Short Circuit study, and would address staff's concrens as stated in the preliminary Staff Assessment about modeling of interconnection facilities and the new 500 kV bulk power line, and would include all downstream adverse impacts and selected mitgation measure(s) for each criteria violation. According to staff's discussion with the representative of K. R. Salines & Associates, the Transient Stability study and Short Circuit study to be performed by SCE must include analyses for the affected Western, SCE, IID and SDG&E systems.

2. The SIS and/or FS to be performed by Western would include a Power Flow study under 2006 summer peak and 2006 spring conditions, and would address staff's concrens as stated in the preliminary Staff Assessment about modeling of interconnection facilities and the new 500 kV bulk power line, and would include all downstream adverse impacts and selected mitgation measure(s) for each crteria

violation. If SCE does not perform a Transient Stability study and a Short Circuit study for the affected Western system, the SIS and/or FS to be performed by Western must include such analyses for the affected Western system.

3. The SIS and/or FS to be performed by IID would include a Power Flow study under 2006 summer peak and 2006 spring conditions, and would address staff's concrens as stated in the preliminary Staff Assessment about modeling of interconnection facilities and the new 500 kV bulk power line, and to include all downstream adverse impacts and selected mitgation measure(s) for each crteria violation. If SCE does not perform a Transient Stability study and a Short Circuit study for the affected IID and SDG&E systems, the SIS and/or FS to be performed by IID must include such analyses for the affected IID and SDG&E systems.
4. For any proposed new or modified downstream faclilities, including reconductoring outside a substation fence line, environmental impact information is required.
5. Review, Analysis and Conclusions by the Cal-ISO on the SCE, Western and IID SISs and/or Facility studies.
6. Final layout plans with description of faclities and one line diagrams for the BEP II Switchyard, Buck Blvd. Substation, the new 500 kV line and Devers substation (Coachella or Dillon Road Substation be included if necessary) with proposed equipment and their ratings in concurrence with the respective transmission owner.
7. A copy of the "request to interconnect BEP II" by the applicant to Western, and the associated work plan and schedules for completing the SIS and/or FS.
8. A copy of the "request to terminate the proposed new 500 kV line" by IID to SCE and Western, and the associated work plan and schedules for completing the SIS and/or FS.
9. Evidence that the CEQA/NEPA reviews have made adequate progress to ensure that construction of the 500 kV line and its schedule have been finalized by IID, that the 500 kV line has been approved for termination by SCE and Western, , and that a schedule for building any other new or modified downstream facilities necessary to comply with reliability criteria have been finalized.

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CEC (California Energy Commission). 2003c. Third Round Data Requests. 05/07/2003 (tn: 28635)

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NERC (North American Electric Reliability Council) 1998. NERC Planning Standards, September 1997.

WECC (Western Electricity Coordinating Council) 2001. NERC/WECC Planning Standards, June 2001.

DEFINITION OF TERMS

ACSR	Aluminum cable steel reinforced.
SSAC	Steel Supported Aluminum Conductor.
AAC	All Aluminum conductor.
Ampacity	Current-carrying capacity, expressed in amperes, of a conductor at specified ambient conditions, at which damage to the conductor is nonexistent or deemed acceptable based on economic, safety, and reliability considerations.
Ampere	The unit of current flowing in a conductor.
Kiloampere (kA)	1,000 Amperes
Bundled	Two wires, 18 inches apart.
Bus	Conductors that serve as a common connection for two or more circuits.
Conductor	The part of the transmission line (the wire) that carries the current.
Congestion Management	Congestion management is a scheduling protocol, which provides that dispatched generation and transmission loading (imports) would not violate criteria.
Emergency Overload	See Single Contingency. This is also called an L-1.
Kcmil or KCM	Thousand circular mil. A unit of the conductor's cross sectional area, when divided by 1,273, the area in square inches is obtained.
Kilovolt (kV)	A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground. 1,000 Volts.
Loop	An electrical cul de sac. A transmission configuration that interrupts an existing circuit, diverts it to another connection and returns it back to the interrupted circuit, thus forming a loop or cul de sac.
Megavar	One megavolt ampere reactive.
Megavars	Megavolt Ampere-Reactive. One million Volt-Ampere-Reactive. Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system.

Megavolt ampere (MVA)
A unit of apparent power, equals the product of the line voltage in kilovolts, current in amperes, the square root of 3, and divided by 1000.

Megawatt (MW)
A unit of power equivalent to 1,341 horsepower.

Normal Operation/ Normal Overload
When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating.

N-1 Condition
See Single Contingency.

Outlet Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation facilities to the main grid.

Power Flow Analysis
A power flow analysis is a forward looking computer simulation of essentially all generation and transmission system facilities that identifies overloaded circuits, transformers and other equipment and system voltage levels.

Reactive Power
Reactive power is generally associated with the reactive nature of inductive loads like motor loads that must be fed by generation units in the system. An adequate supply of reactive power is required to maintain voltage levels in the system.

Remedial Action Scheme (RAS)
A remedial action scheme is an automatic control provision, which, for instance, would trip a selected generating unit upon a circuit overload.

SF6 Sulfur hexafluoride is an insulating medium.

Single Contingency
Also known as emergency or N-1 condition, occurs when one major transmission element (circuit, transformer, circuit breaker, etc.) or one generator is out of service.

Solid dielectric cable
Copper or aluminum conductors that are insulated by solid polyethylene type insulation and covered by a metallic shield and outer polyethylene jacket.

Substation A power plant Substation (Substation) is an integral part of a power plant and is used as an outlet for one or more electric generators.

Thermal rating
See ampacity.

TSE Transmission System Engineering.

TRV Transient Recovery Voltage

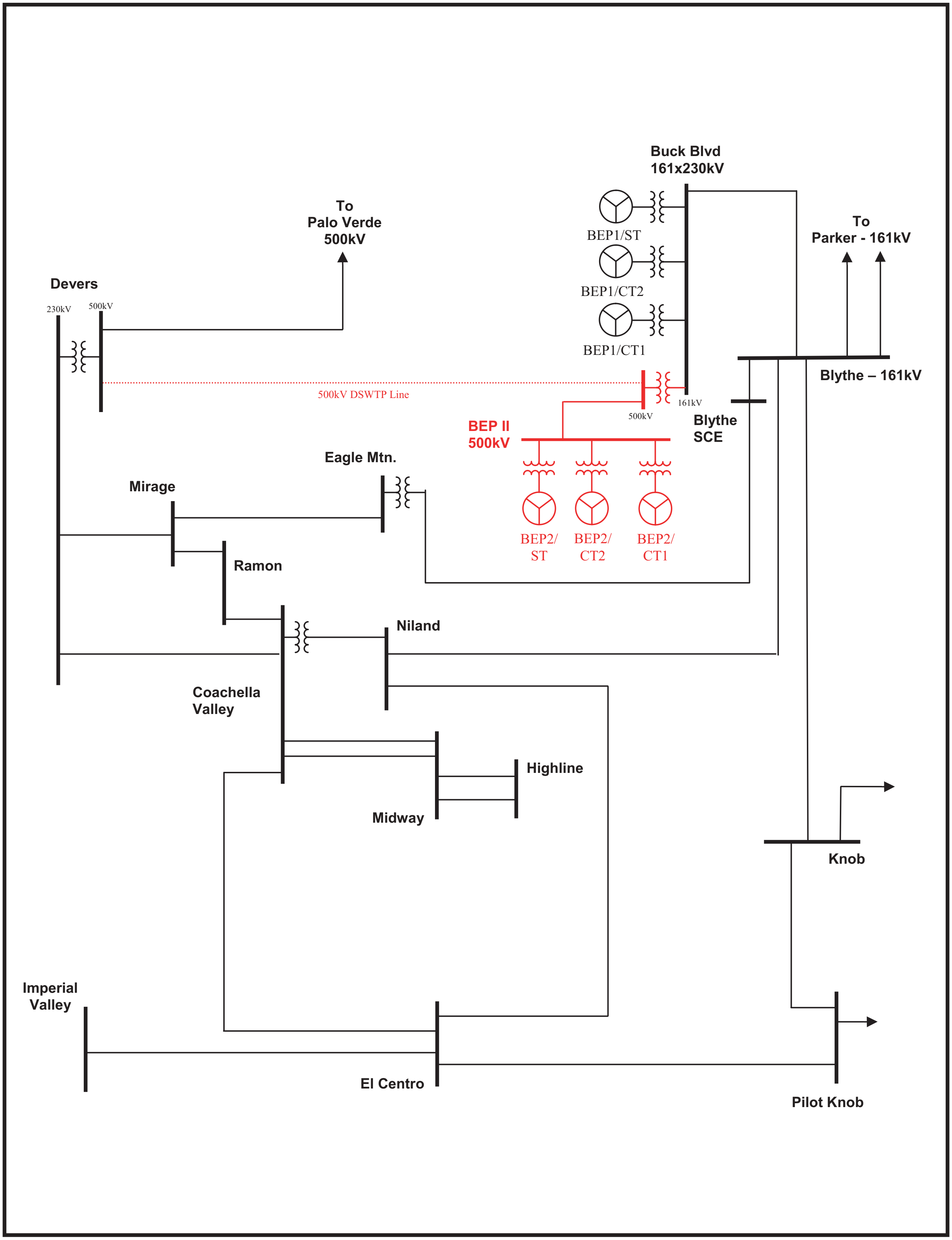
Tap A transmission configuration creating an interconnection through a sort single circuit to a small or medium sized load or a generator. The new single circuit line is inserted into an existing circuit by utilizing breakers at existing terminals of the circuit, rather than installing breakers at the interconnection in a new Substation.

Undercrossing
A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.

Underbuild
A transmission or distribution configuration where a transmission or distribution circuit is attached to a transmission tower or pole below (under) the principle transmission line conductors.

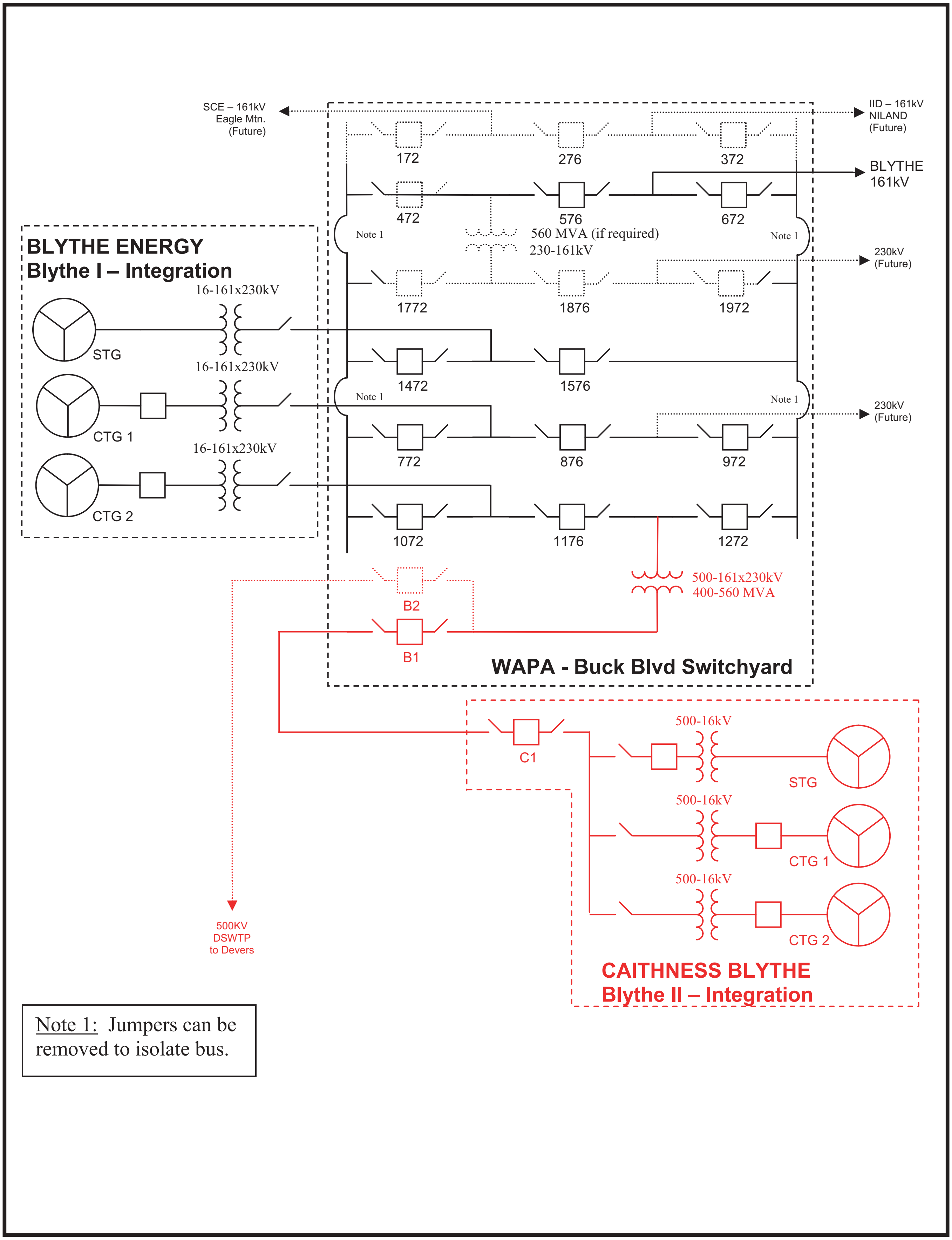
TRANSMISSION SYSTEM ENGINEERING - FIGURE 1

Blythe Energy Project Phase II - System One-Line



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

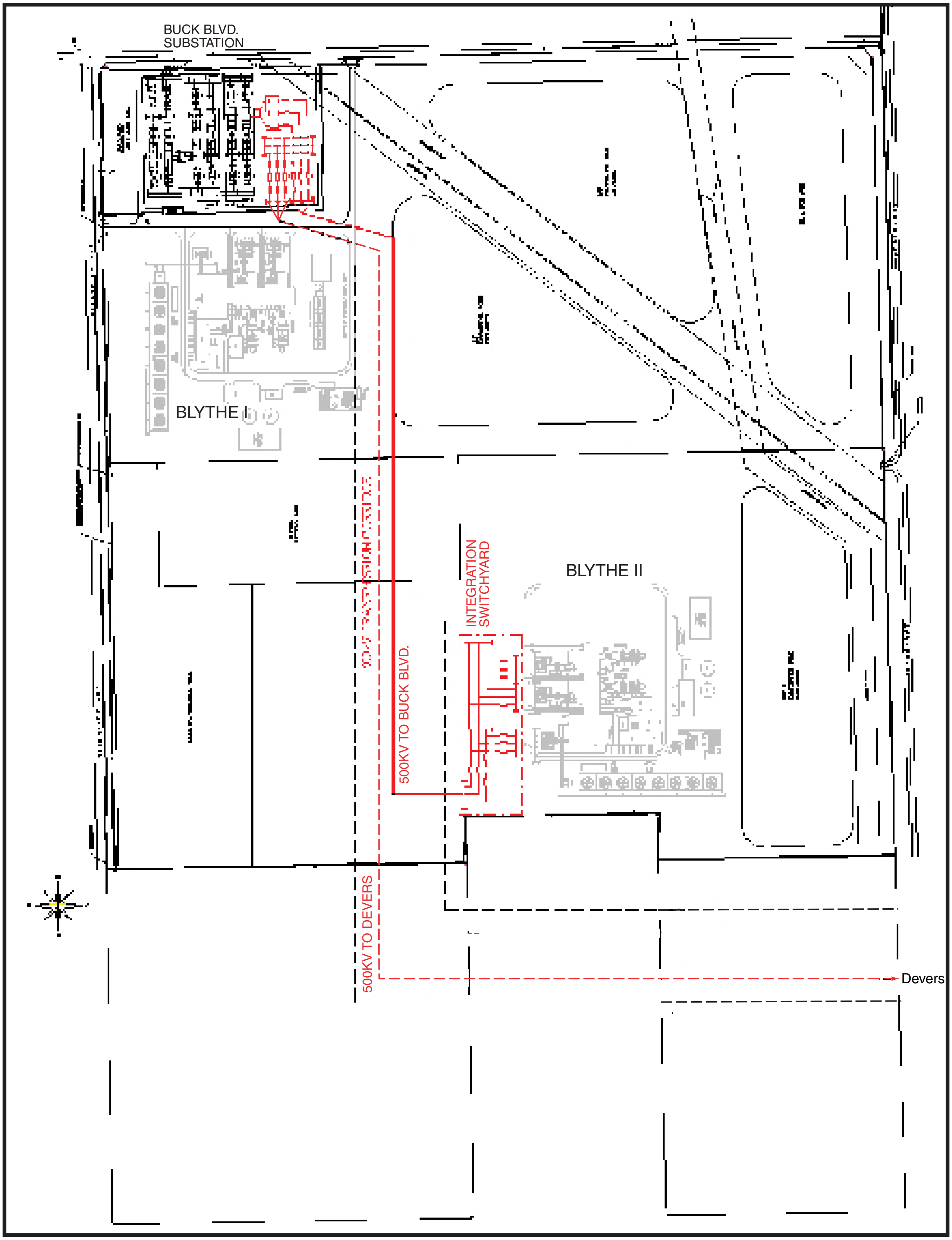
SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003.



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003, Revised by CEC Staff.

TRANSMISSION SYSTEM ENGINEERING - FIGURE 3

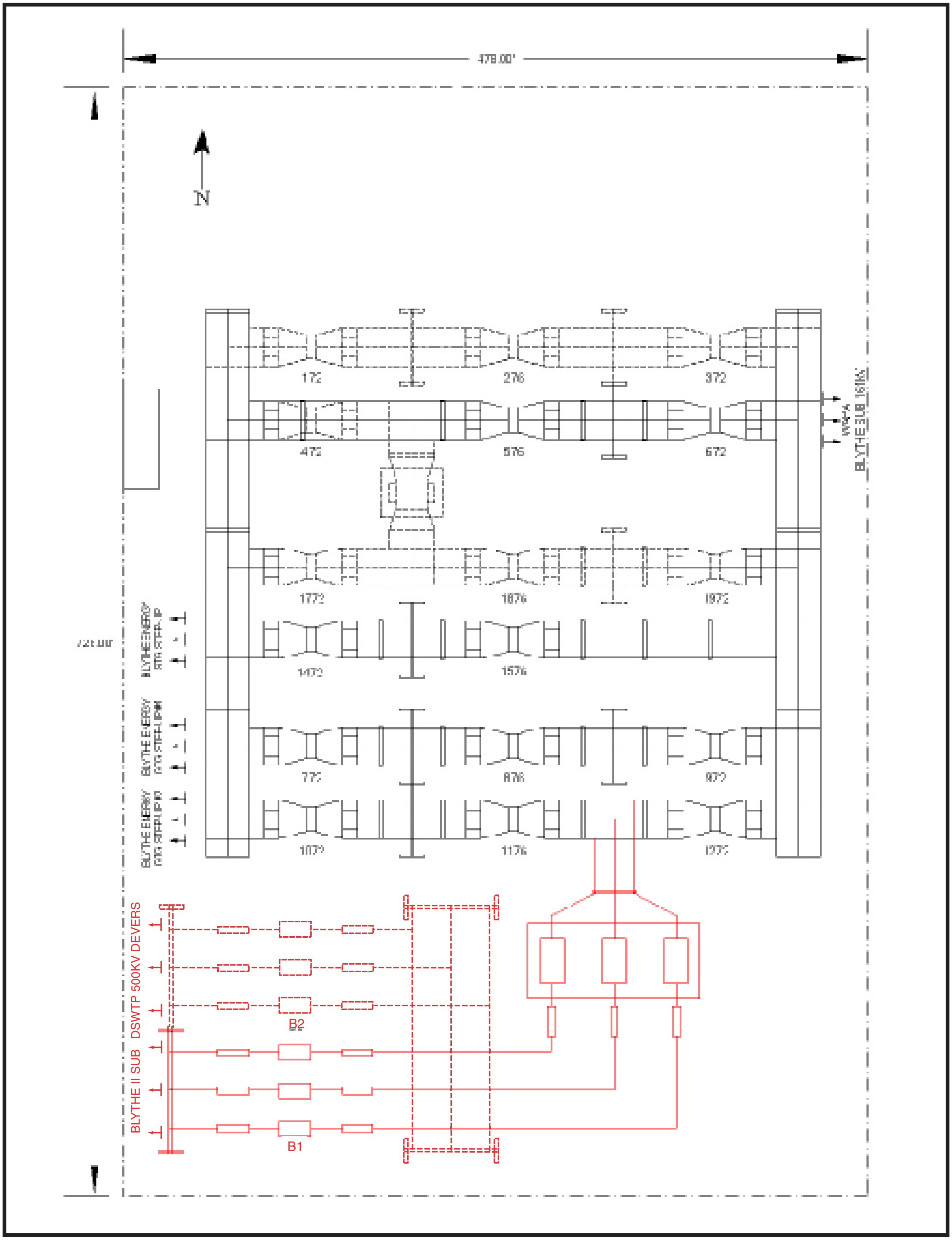
Blythe Energy Project Phase II - Blythe Site, General Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003, Revised by CEC Staff.

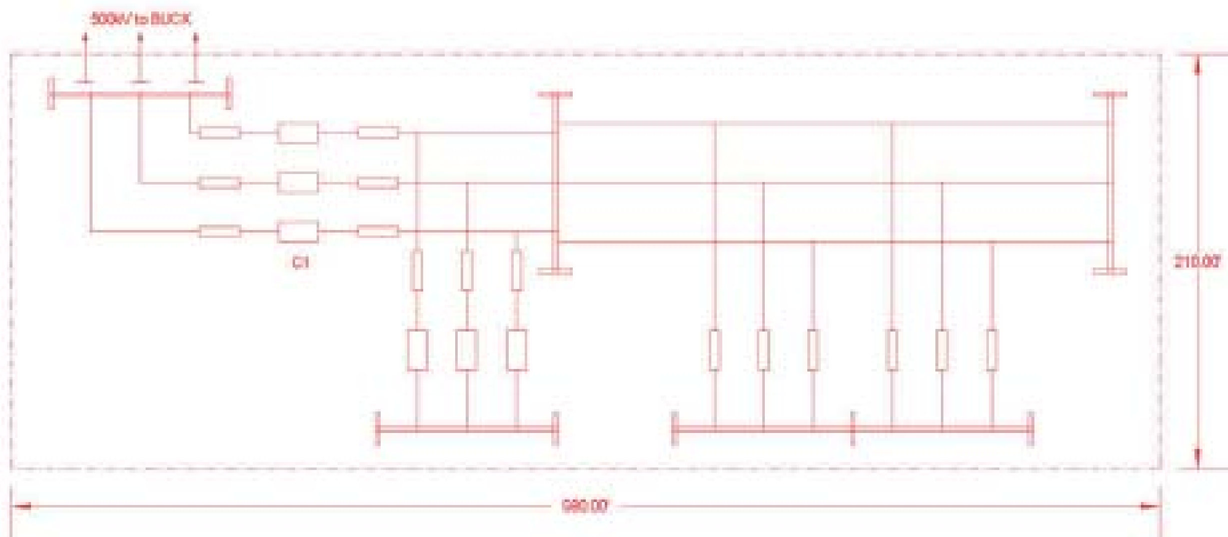
TRANSMISSION SYSTEM ENGINEERING - FIGURE 4
Blythe Energy Project Phase II - Buck Blvd. Substation, General Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003
SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003.

TRANSMISSION SYSTEM ENGINEERING - FIGURE 5

Blythe Energy Project Phase II - Integration Switchyard, General Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003.

ALTERNATIVES

Susan V. Lee

INTRODUCTION

This section considers potential alternatives to the construction and operation of the proposed Blythe Energy Project Phase II (BEP II). The purpose of this alternatives analysis is to comply with State and Federal environmental laws by providing an analysis of a reasonable range of feasible alternative sites which could substantially reduce or avoid any potentially significant adverse impacts of the proposed project (Cal. Code Regs., tit. 14, §15126.6; Cal. Code Regs., tit. 20, §1765). This section identifies potentially significant impacts of the proposed project and analyzes different technologies and alternative sites that may reduce or avoid significant impacts. Staff has also analyzed the impacts that may be created by locating the project at alternative sites.

The California Energy Commission (Energy Commission) does not have the authority to approve an alternative or require Caithness Blythe II, L.L.C. (Caithness) to move the proposed project to another location, even if it identifies an alternative site that meets the project objectives and avoids or substantially lessens on one or more of the significant effects of the project. Implementation of an alternative site would require that the applicant submit a new Application for Certification (AFC), including revised engineering and environmental analysis. This more rigorous AFC-level analysis of any of the alternative sites could reveal environmental impacts, non-conformity with laws, ordinances, regulations, and standards; or potential mitigation requirements that were not identified during the more general alternatives analysis presented herein. Preparation and review of a new AFC would require substantial additional time.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Caithness proposes to interconnect the proposed BEP II to the new Buck Boulevard Substation, which is under the jurisdiction of the Western Area Power Administration (Western). Since Western is a federal agency, the BEP II project may be subject to review under the National Environmental Policy Act (NEPA) in addition to the California Environmental Quality Act (CEQA). Western is the Lead Agency under NEPA and the California Energy Commission is the Lead Agency under CEQA.

CALIFORNIA ENVIRONMENTAL QUALITY ACT CRITERIA

The “Guidelines for Implementation of the California Environmental Quality Act,” Title 14, California Code of Regulation, Section 15126.6(a), provides direction by requiring an evaluation of the comparative merits of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project.” In addition, the analysis must address the “no project” alternative (Cal. Code Regs., tit. 14, §15126.6(e)).

The range of alternatives is governed by the “rule of reason” which requires consideration only of those alternatives necessary to permit informed decision-making and public participation. CEQA states that an environmental document does not have to consider an alternative of which the effect cannot be reasonably ascertained and of which the implementation is remote and speculative (Cal. Code Regs., tit. 14, §15125(d)(5)).

PROJECT DESCRIPTION

The proposed BEP II would be a nominal 520 megawatt (MW) natural-gas-fired generating facility located on approximately 15-20 acres within a 76-acre parcel. The site is located to the east of the Blythe Airport, which is owned by Riverside County and operated by the City of Blythe and is immediately adjacent to the Blythe Energy Phase I (BEP I) power plant. The City of Blythe, centered five miles to the west, annexed and incorporated the project site within the City limits. The land is currently zoned for industrial uses (BEP II 2002a). The BEP II would include equipment identical to the Blythe Energy Phase I facility.

The proposed power plant would require no offsite natural gas pipelines. Natural gas for the facility would be delivered via the gas pipeline constructed as part of BEP I. As currently proposed, a new 2,500 foot long 500 kV transmission line would connect BEP II to the existing Buck Boulevard Substation, which was constructed as part of BEP I. From the Buck Boulevard Substation a new 118-mile 500 kV transmission line would be constructed to the Devers Substations. This transmission line is currently being evaluated as Imperial Irrigation District's (IID) Desert Southwest Transmission Line EIS/EIR, but has not yet been approved. The IID proposed transmission line is not part of the proposed project, and will be addressed only as part of the cumulative impact analysis. This Staff Assessment will only consider the transmission line project in the IID EIS/EIR, not any of the alternatives.

If the Desert Southwest Transmission Line Project is not constructed in a timely fashion, transmission from the Buck Boulevard Substation could also possibly connect to the Midway Substation, owned by IID, and as originally proposed by the Applicant. A system impact study would need to be performed. The Blythe Substation interconnects five existing 161-kV regional transmission lines. Three transmission lines are owned by Western, one by IID, and the other by Southern California Edison (SCE). IID may also plan to construct a new double-circuit 230-kV connection from BEP II to the Midway Substation. However, this line has not yet been approved and so it is not considered as a feasible transmission connection option for the proposed project. A system impact study would be necessary to confirm technical and economic feasibility if this interconnection is necessary.

BEP II, as proposed, would rely on groundwater derived from an additional well located on the project site to supply approximately 2,220 gallons per minute (gpm) (averaging 3,262 acre-feet per year) of cooling water for the project's proposed wet (evaporative) cooling system. BEP II would duplicate supply and wastewater treatment systems being constructed as part of BEP I. An evaporation pond would have to be constructed for BEP II, adding to the two ponds constructed for BEP I. The pond would be subject to the conditions established by the Regional Water Quality Control Board. Additional emergency backup water from BEP I would be used if required due to problems with the on-site well. In addition to the cooling of the steam turbine exhaust, the Applicant proposes to use an inlet air chilling system to cool the air entering the gas turbines in order to improve the efficiency and capacity of the gas turbines, particularly under conditions of high ambient temperature.

A Water Conservation Offset Plan (WCOP) has been proposed by the BEP II Applicant as a voluntary action to comply with anticipated Bureau of Reclamation requirements. The WCOP is not proposed as a mitigation measure, therefore, there are still outstanding issues and potentially significant impacts related to the water source for BEP II that are discussed in greater detail below.

APPLICANT'S SITE SELECTION CRITERIA

The following site selection criteria were used by the applicant for choosing the proposed site; however, Staff does not necessarily concur that all the criteria must be met when analyzing alternative sites. The critical project objectives, as determined by Staff, are listed in the following section. According to the AFC, the applicant chose the proposed site for the following reasons (BEP II 2002a):

- The site is adjacent to BEP I;
- The site is in close proximity to existing electrical transmission and natural gas facilities;
- Sufficient land is available;
- The site has environmental compatibility with an expected low impact on the environment, given its proximity to the industrial lands at the airport and BEP I, remoteness from residential areas, elevation above most populated areas, and low traffic conditions; and
- The parcel is located in a designated corridor targeted for industrial development.

SCOPE AND METHODOLOGY OF THE ALTERNATIVES ANALYSIS

The purpose of Staff's alternatives analysis is to provide a reasonable range of feasible alternatives that could substantially reduce or avoid any potentially significant adverse impacts of the proposed project. To accomplish this, Staff must determine the appropriate scope of analysis. Consequently, it is necessary to identify and determine the potentially significant impacts of the proposed project and then focus on alternatives that are capable of reducing or avoiding significant impacts.
To prepare this alternatives analysis, Staff used the following methodology:

1. Provide an overview of the project, identify the basic objectives of the project, and describe its potentially significant adverse impacts.
2. Identify and evaluate technology alternatives to the project such as increased energy efficiency (or demand side management) and the use of alternative technologies (e.g. wind, solar, or geothermal energy).
3. Identify and evaluate alternative locations or sites.
4. Evaluate the impacts of not constructing the project, known as the "no project" alternative under CEQA.

PROJECT OBJECTIVES

Based on analysis of the BEP II AFC, the Energy Commission Staff has determined the project's objectives as:

∉ Construction and operation of a merchant power plant with access to multiple markets;

∉ Location near a substation and key infrastructure for natural gas, water supply and transmission lines;

∉ Generation of approximately 520 MW of electricity.

While the Applicant also included an objective of co-location with BEP I to minimize operational and maintenance costs, Staff felt it important to the analysis to explore other possible sites. Therefore, Staff did not utilize this objective when analyzing feasible alternatives.

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS

In this PSA, Staff has identified the potential for significant environmental effects of the proposed project in the following technical areas (summarized below): air quality, cultural resources, land use, socioeconomics/environmental justice, traffic and transportation, transmission system engineering, and water and soil resources.

AIR QUALITY

The proposed BEP II is located in the Mojave Desert Air Quality Management District (MDAQMD) and many of the emissions reduction credits (ERCs) have been identified but have not yet been verified or issued. In addition, many of the proposed ERCs would be issued by the district to a third party and then would have to be purchased by the applicant. It is not clear whether the applicant has purchase agreements with any of the identified third parties. The applicant proposes to secure its ERCs in parallel with the siting process, which could cause scheduling delays.

The Water Conservation Offset Program (WCOP) for the BEP II proposes to leave 717 acres of farmland fallow for the life of the project or implement a rotational fallowing program for an equivalent number of acres. According to the Natural Resources Conservation Service (NRCS), the landowner of such land would be responsible for limiting the wind blown soil erosion from the land to less than 5 ton/acre-year. Staff is concerned that if a significant portion of the wind blown erosion from such fallow land is PM10, the WCOP could effectively add a substantial quantity of airborne PM10 to the region. Further, the soil erosion rates would vary from year to year, depending on annual precipitation, groundwater pumping rates, tilling activity, ultimate ground cover viability, and rotation of fallowing.

In addition, Staff has requested information on organic components in the cooling water and wind erosion control of WCOP lands. The Final Staff Assessment will characterize the air quality effects of these issues based on any new information that may come as a result of the Soil & Water analysis.

Finally, the United States Environmental Protection Agency has commented on numerous recent projects that the Best Available Control Technology (BACT) level for NOx should be 2.0 parts per million by volume, dry basis (ppmvd) on a one-hour average and the BACT level for Carbon Monoxide (CO) should be 2.0 ppmvd on a three-hour average. The applicant has proposed a BACT level for NOx of 2.5 ppmvd on a one-hour average and a BACT level for CO of between 5.0 and 8.4 ppmvd (depending on load) on a three-hour average. The MDAQMD still needs to issue a Final Determination of Compliance (FDOC), and in the process the Applicant may be forced to change their proposal. The U.S. EPA and CARB requested that many changes be included in the MDAQMD's FDOC, and it is not yet clear whether MDAQMD will implement all of the requests made by these oversight agencies.

It is not clear whether BEP II would be likely to comply with requirements for BACT because the determination made by MDAQMD is inconsistent with U.S. EPA and CARB recommendations. The U.S. EPA believes that the offset strategy for PM_{10} is invalid and that special case-by-case approval of the offset interpollutant trading scheme is required. If these concerns are not addressed before the MDAQMD issues the FDOC, additional mitigation may be necessary to address project-related impacts to PM_{10} and ozone from precursor emissions. Because the offset strategy is incomplete, Staff cannot determine whether BEP II would be likely to comply with MDAQMD offset rules or whether impacts to PM_{10} and ozone would be mitigated to a level of insignificance.

CULTURAL RESOURCES

The City of Blythe has not concluded its planning process. The City may require ground-disturbing activities outside of the project site. If ground-disturbing activities are required outside of the project site, other resources could be identified or known resources could be impacted. Any newly identified resources would have to be evaluated to determine if it meets the eligibility requirements for the California Register of Historic Resources. Impacts and mitigation measures cannot be determined until evaluation is completed.

LAND USE

The project is consistent with the City's General Plan and generally consistent with the City's zoning. However, the project would exceed the City's 34-foot height restriction in the Heavy Industrial Zone, and thus requires a height variance.

The WCOP has the potential to cause significant adverse impacts to agricultural resources in the area and could be in conflict with County and City goals and policies that encourage retention of agricultural land. The WCOP would affect agricultural land or land that can be used for agriculture, either on the Mesa or in the Palo Verde Valley.

The *Comprehensive Land Use Plan for Blythe Airport, Riverside County, California (CLUP)* was adopted by the Riverside County Airport Land Use Commission (ALUC) in August of 1992. The ALUC has determined that the project is inconsistent with the CLUP, while recommending conditions if the Commission decides to approve the project. The City has not yet submitted its review and recommendation to the Energy Commission regarding the ALUC's determination. Staff needs to receive the City's review and recommendation in order to decide whether to recommend that the Energy Commission either override or accept the ALUC's determination of inconsistency.

The potential for land use compatibility impacts, including cumulative impact, of visual water vapor plumes and thermal plumes caused by the project are unknown.

SOCIOECONOMICS/ENVIRONMENTAL JUSTICE

The BEP II should result in some benefits for Riverside County from property and sales tax. The City of Blythe may also benefit from the economic activity that may be generated by the purchase of services, manufactured goods and equipment from local businesses. However, the Applicant has proposed a voluntary Water Conservation Offset Program (WCOP) to offset the project's use of Colorado River water pumped as groundwater. The plan would call for BEP II to fallow land that has been under agricultural use within the last five years to offset the project's annual use of approximately 3,300 acre-feet of Colorado River water. The information provided by the applicant indicates that a value of 4.2 acre-feet of water per acre of land fallowed would be used to calculate the number of acres that would need to be fallowed to offset the project's water use. Implementation of the WCOP would result in changes to the agricultural use of some lands in the vicinity of the proposed project.

Based on the limited information provided by the applicant, staff cannot determine whether a significant impact to the farm labor, farm services, and farm supply sector will occur. Without additional information, it would be concluded that the project could have a disproportionately impact on the minority and low-income population of Mesa Verde. In order to complete the Final Staff Assessment, the applicant will need to provide full details on the proposed fallowing of croplands.

TRAFFIC AND TRANSPORTATION

Due to concerns raised by a local pilot and aviation business owner regarding air traffic safety associated with thermal and visual plumes, Staff has asked the FAA and the Caltrans Aeronautics Division to review the BEP II's proposed site plan in light of these plume-related aviation safety concerns and run an additional plume analysis during the winter months when sizable plumes are most likely.

Due to these outstanding issues regarding aviation safety, the Traffic and Transportation Section of the FSA cannot be completed until receipt of adequate assessment by the applicant, aviation agencies, and/or consultants of the impact of visual and thermal plumes, including the cumulative impact of BEP AND BEP II, on airport traffic safety. If the Energy Commission certifies the Blythe Energy Project Phase II, Staff recommends that the Commission adopt Staff's proposed Conditions of Certification. With further information Staff may recommend additional conditions.

TRANSMISSION SYSTEM ENGINEERING

The Applicant is proposing to electrically interconnect into the region's transmission system at the Buck Boulevard Substation, located at the northeastern corner of the BEP I site. Western constructed the substation as part of the BEP I project.

The current System Impact Study (SIS), considered as a screening and feasibility study, is found incomplete and the study results are preliminary. Staff is not confident that the Power Flow study results have identified all system reliability criteria violations and their degree of impacts in the affected systems of SCE, IID, SDG&E and Western. The study reports for Transient Stability and Short Circuit analyses have not yet been provided.

In addition, Staff is awaiting Cal-ISO verification of the applicant's proposal to mitigate most of the identified new or existing pre-project overload violations due to addition of BEP II. The present report by the applicant suggests that the applicant will discuss mitigation measures with the respective transmission owners and then incorporate selected mitigation measures in the final SIS report.

Finally, to facilitate adequate transmission capacity for additional power flow from the BEP II generation or for the combined generation of BEP I and BEP II, the applicant has identified a new 500 kV, 118-mile Desert Southwest Transmission Line Project (DSWTP) from Western's Buck Blvd Substation to SCE's Devers Substation, which is under consideration to be built by IID as the project's primary transmission service. However, Staff has no information from the applicant or IID about the status of building the DSWTP and its expected completion date. Staff is also not aware if IID has filed any "request to terminate" to Western and SCE for connecting the proposed new line to SCE and Western systems. Also no information has been received from the applicant or SCE or Western about specific details of the new and/or modified facilities involved in the SCE and Western Substations to accommodate the new line. Therefore, the feasibility of building the new line in a timely manner before the projected on-line date of BEP II remains uncertain at this stage and consequently the feasibility of the BEP II project also remains uncertain.

WATER AND SOIL RESOURCES

The applicant has proposed to supply water to operate the facility by installing one additional groundwater well having the capacity to pump up to 3,000 gallons per minute. Staff determined that this would result in a significant direct and cumulative impact to the Palo Verde Irrigation District (PVID) water supply and its users, and a contribution to a significant impact to the State's Colorado River water supply and its users that are directly related to the projects use of Colorado River groundwater.

To offset water consumption pumped as groundwater and to ensure that there is no net change within the PVID, the applicant has included a Water Conservation Offset Program (WCOP) as a voluntary measure separate from mitigation. The WCOP does not mitigate or eliminate the project's consumptive use of this water source, and is inadequate as a mitigation measure for the purposes of CEQA and for conformance to applicable LORS. Staff has concerns about the practical effectiveness of this proposed mitigation. If the WCOP is found to be inadequate then there could be significant cumulative impacts to the region's hydrologic system.

In addition, many of the soils within the mesa and valley areas are listed as Prime Agricultural land and Highly Erodible Lands (HEL). Staff is concerned that if the lands are not properly managed, the proposed project could result in significant degradation of the soils and agricultural productivity and soil loss rates via wind and water erosion could exceed the maximum threshold of five tons/acre/year on the fallowed lands. Construction and operations at the BEP II site could potentially result in increased stormwater runoff volumes and peak flowrates, thus potentially resulting in significant impacts to downstream properties.

Finally, BEP II submitted a Waste Discharge Permit Application to the RWQCB that contained an erroneous estimate of evaporation pond capacity. Discharge of wastewater from the BEP II facility to the proposed evaporation pond could result in significant impacts to soil and groundwater quality as a result of leaks or overflows from the proposed evaporation pond.

Due to the aforementioned potentially significant water concerns, Staff is analyzing the feasibility, potential impacts, and costs of three alternative cooling technologies that could be used at BEP II. Dry cooling and hybrid cooling using non-potable water for evaporative cooling or in conjunction with dry cooling air cooled condensers are fully evaluated in the Water Supply and Cooling Options study in Appendix A of this Staff Assessment, and, therefore, are not analyzed in this section.

SITE ALTERNATIVES

Four alternative sites have been identified. The applicant presented two of these as part of its alternatives analysis (Alternative Site A, South of the City of Blythe Site and Site B, Blythe Airport Site; BEP II 2002a). Staff identified two additional potential alternative sites, the Interstate 10 Alternative Site and the Devers Alternative Site. All four sites were retained for analysis and are evaluated below.

SCREENING CRITERIA USED TO SELECT ALTERNATIVE SITES

The following criteria were used to identify potential alternative sites. Each site was evaluated for its ability to:

1. Avoid or substantially lessen one or more of the potential significant effects of the project as described above;
2. Satisfy the following criteria:
   a. Location. In order to meet reliability objectives, the site should be located near major regional grid system for transmission lines.
   b. Site suitability. Sufficient land is needed to construct and operate a generating facility of this size. The proposed power plant would be located on 76 acres of land, however only 15-20 acres are required for a generating facility using the proposed technology (BEP II 2002a). Therefore, Staff used 20 acres as the minimum lot size needed to accommodate the facility.
   c. Availability of infrastructure. The site should be within a reasonable distance of natural gas and water supply.
3. Not create significant impacts of its own.
4. Be sufficiently far from moderate or high density residential areas or to sensitive receptors (such as schools and hospitals) or to recreation areas.

Based on these screening criteria, four alternative sites were selected for further evaluation in this PSA: South of Blythe Site (applicant's Site A), Blythe Airport Site (applicant's Site B), Interstate 10 Site (identified by Staff-Site C), and Devers Site

(identified by Staff-Site D). Please see **ALTERNATIVES Figures 1 and 2** for maps of these sites.
The alternative sites analyses focus on the disciplines for which impacts were initially identified for the proposed project: land use, water and soil resources, cultural resources, transmission system engineering, air quality, and traffic and transportation. In addition, visual resources, geological concerns, biological resources, noise, and hazardous materials were considered where potentially significant impacts were identified in connection with an alternative site.

SOUTH OF BLYTHE SITE

The South of Blythe Site (applicant's alternative Site A) is located south of the City of Blythe in the Palo Verde Valley. It is bordered to the north by 16th Avenue, to the south and east by the Atchison, Topeka, and Santa Fe Railroad line, and to the west by Lovekin Boulevard. The City of Blythe is planning on incorporating this area for development and zoning it for commercial and/or industrial uses. The site consists of approximately 150 acres of land. The site is currently in agricultural use and is surrounded by industrial and agricultural land uses.

The nearest location to tie into the regional electrical grid would be Western's Blythe Substation, approximately 5.5 miles to the northwest. Access to this substation would require the construction of overhead transmission lines along the agricultural lands of the Palo Verde Valley and up the east face of Palo Verde Mesa. Similar to the proposed project, water would likely be supplied via a groundwater well. A natural gas pipeline would have to be constructed south along Lovekin Boulevard to connect to two SoCalGas pipelines that run along 14th Street, about one mile north of the site.

The site has a level topography. Adjacent land uses include a sewer plant north of the proposed site, an auto-recycling yard to the west, storage tanks south of the site, and a hay storage facility on the eastern side of the site. In addition, there are several residences interspersed on 16th Avenue and approximately nine trailer homes on Lovekin Boulevard. The nearest residence is on the west side of Lovekin Boulevard, approximately 250 feet from the edge of the site property.

<u>Impact Discussion</u>

Following is a discussion of potential environmental impacts at the South of Blythe Site:

- **Air Quality**: This site is located in the MDAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project. Assuming that outstanding issues related to the proposed project are resolved and mitigation measures are developed to reduce proposed project impacts to less-than-significant levels, similar conclusions and measures would apply to this alternative site to reduce air quality impacts to less-than-significant levels.
- **Cultural Resources**: To determine potential impacts of a project at this site and along the routes of linear facilities, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. Because the site is in agricultural use and is already disturbed, it is unlikely that there would be significant impacts to cultural resources with implementation of standard mitigation measures. Siting of the towers and construction of overhead

transmission lines up the east face of Palo Verde Mesa to Blythe Substation have the potential to encounter known or unknown cultural resources in the area, but a cultural resources assessment would be necessary to determine the impact significance.

- **Land Use**: The City of Blythe is planning on incorporating this area for development and zoning it for commercial and/or industrial uses. This site is farther from the airport and would be less likely to interfere with airport operations, however, it is also closer to the City of Blythe and several sensitive receptors, which could cause significant impacts. The land use impacts resulting from the WCOP would be the same as the proposed project, because the project at this alternative site would still be using water from the Colorado River.
- **Socioeconomics/Environmental Justice**: If this site proposes to use a WCOP, it could have a disproportionately impact on the minority and low-income population of the area. As with the BEP II project, additional information is needed on how the WCOP would be implemented before a conclusion can be made.
- **Traffic and Transportation**: This site is located southeast of the proposed project site and considerably farther from the Blythe Airport, therefore, a power plant at this site would not likely affect airport traffic safety and impacts would be less than significant.
- **Transmission System Engineering**: This site would require the construction of a new 5.5-mile transmission line for interconnection into the regional electrical grid. As with the proposed project, there are similar uncertainties about reliability; therefore, an interconnection study would be necessary to determine whether system impacts would be less than significant.
- **Water and Soil Resources**: The same water supply impacts resulting from the proposed project would also occur at this site because both would pump water from groundwater wells ultimately routed to the Colorado River. Similar mitigation measures to BEP II would be required to reduce potential impacts from the WCOP to less than significant.

  Though there is not a landfill onsite, there could be potential groundwater contamination issues associated with the nearby auto-recycling yard. Similar mitigation measures to those required for the proposed BEP II would be required.

  As with the proposed project, the project's use of groundwater at this site would also result in significant impacts. Thus, an alternative cooling technology such as dry or hybrid cooling would likely be required to minimize impacts to groundwater.
- **Noise**: The nearest residence to the proposed project is approximately 0.75 miles southwest of the site. Therefore, the closer proximity of the nearby residences and sensitive receptors and the City of Blythe would increase the potential for significant impacts from project construction and operation. Extensive noise mitigation would be required to reduce this impact to less than significant.
- **Biological Resources**: Due to the disturbed nature of the site, it is unlikely that there would be significant impacts to biological resources. However, the construction of the transmission line would affect the desert flora located on the east face of the mesa. Due to low rainfall and elevations, coupled with extreme

temperatures, the vegetation in the project area is typically drought-adapted, simple, sparse, and easily susceptible to impact from disturbance. However, standard mitigation (e.g., site fencing for desert tortoises, surveys for burrowing owl nests, worker education, etc.) would likely reduce potential biological impacts to less than significant.

- **Hazardous Materials**: The risk associated with use and transport of anhydrous ammonia and other hazardous materials at the South of Blythe Site would be greater than at the proposed project site due to the proximity of sensitive receptors and transport through the City of Blythe. Mitigation would likely be required for LORS compliance and to reduce potential impacts to less than significant.
- **Geological Resources**: The South of Blythe Site is located on the Palo Verde Valley floor, which has a higher groundwater table than at the proposed project site. This increased soil saturation could pose an increased seismic risk due to potential liquefaction of the soil. Mitigation measures and/or changes in plant design and construction to withstand ground shaking in the event of a major earthquake would be necessary to reduce this impact to less than significant.
- **Visual Resources**: The close proximity to the City of Blythe and to nearby residences has the potential for significant visual impacts to be created at this site. In addition, the proposed transmission line, which would cross primarily agricultural lands and up the east side of the mesa, would most likely be highly visible from the City of Blythe and the Colorado River and might cause significant visual intrusion. Mitigation, such as landscaping or power plant color, could reduce this impact to less than significant, but this cannot be determined with certainty without more detailed study and analysis of photosimulations.

BLYTHE AIRPORT SITE

The Blythe Airport Site (applicant's alternative Site B) is located within the Blythe Airport property boundary on the Palo Verde Mesa and is zoned Industrial-Commercial. The airport is currently under a long-term 75-year lease with the City of Blythe by Riverside County. The site is located to the northeast of the northwest-southeast runway. It is bordered to the northeast by the airport perimeter road, to the southeast and northwest by vacant land, and to the southwest by one of the airport taxiways. There are no residences within a half-mile of the site.

This site is generally flat and currently vacant with up to 257 acres available for development. It is at the same elevation as the airport and facilities.

The project would require the construction of either a 2.5-mile transmission line southeast to the Buck Boulevard Substation or a 3-mile line southeast to Western's Blythe Substation. In addition, the Hobsonway Substation is a substation proposed by the IID that is currently under environmental review and would be located on the north side of Hobsonway, adjacent to BEP I and BEP II projects, and 4.5 miles west of Blythe. As part of the Desert Southwest Transmission Line Project, this proposed substation would connect to a proposed 118-mile 230 kV or 500 kV transmission line west to Devers Substation, which is owned by Southern California Edison Company (SCE). This project may be able to tie into this system, but an interconnection study would be necessary to determine feasibility. This site would require the extension of the natural gas pipeline from the original BEP I site or the construction of a new gas pipeline to one of the two SoCalGas pipelines, located approximately 2.75 miles south of the site. These underground pipeline routes would likely run along the eastern airport boundaries and traverse over mostly unimproved land. Similar to the proposed project, water would likely be supplied via a groundwater well.

Impact Discussion

Following is a discussion of potential environmental impacts at the Blythe Airport Site:

- **Air Quality**: This site is located in the MDAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project. Assuming that outstanding issues related to the proposed project are resolved and mitigation measures are developed to reduce proposed project impacts to less-than-significant levels, similar conclusions and measures would apply to this alternative site to reduce air quality impacts to less-than-significant levels.
- **Cultural Resources**: To determine potential impacts of a project at this site, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. At this time, Staff has not identified any conditions or resources that indicate the potential for the creation of significant impacts; however, the need to construct additional linear facilities (natural gas pipeline and transmission lines) would create greater ground disturbance than at the proposed BEP II site. Standard mitigation would likely reduce any potential impacts to less than significant.
- **Land Use**: The Blythe Airport Site is located within the Blythe Airport property boundary and is zoned Industrial-Commercial. Though the proposed site would be consistent with the land use designation and would not be located in line with any of the runways, there could be potentially significant issues with interference of airport operations due to its proximity and location on the mesa at the same elevation as the runways. However, assuming the airport conflict issues at BEP II are resolved, land use concerns at Blythe Airport Site would be considered less than significant.
- **Socioeconomics/Environmental Justice**: If this site proposes to use a WCOP, it could have a disproportionately impact on the minority and low-income population of the area. As with the BEP II project, additional information is needed on how the WCOP would be implemented before a conclusion can be made.
- **Traffic and Transportation**: This alternative site is within the Blythe Airport property boundary and in closer proximity to the airport. Therefore, an assessment similar to that for the proposed project by the applicant, aviation agencies, and/or consultants of the impact of visual and thermal plumes, including the cumulative impact of BEP (approximately 3 miles east of the site) and the Blythe Airport Site, on airport traffic safety would be necessary to determine the impacts of a power plant at this site. Assuming that outstanding issues are resolved based on the air traffic assessment and mitigation measures are developed to reduce impacts of the proposed project to less-than-significant levels, similar mitigation measures would apply to this alternative site to reduce impacts. However, given its location, the impact at the Blythe Airport Site would still likely remain significant.

- **Transmission System Engineering**: This site would require additional linear facilities to tie into the region's electrical system at Buck Boulevard Substation, the proposed Hobsonway Substation (currently under environmental review), or directly to Western's Blythe Substation. As with the proposed project, there are similar uncertainties about reliability impacts; therefore, similar impacts would occur and an interconnection study would be necessary before Staff could determine whether system impacts would be less than significant.
- **Water and Soil Resources**: The water supply impacts resulting from the proposed project would also occur at this site. It is assumed that this site would use the same water supply as the proposed site due to its proximity to that site. Similar mitigation measures to BEP II would be required reduce potential impacts from the WCOP to less than significant.
  As with the proposed project, the project's use of groundwater at this site would also result in significant impacts. Thus, an alternative cooling technology such as dry or hybrid cooling would likely be required to minimize impacts to groundwater.
- **Biological Resources**: The need to construct additional linear facilities (natural gas pipeline and transmission lines) would create greater ground disturbance than at the proposed BEP II site, which could have a greater effect on biological resources than the proposed project. In addition, the required transmission line would cross the desert flora located on the mesa, which could result in biological impacts. Due to low rainfall and elevations, coupled with extreme temperatures, the vegetation in the project area is typically drought-adapted, simple, sparse, and easily susceptible to impact from disturbance. Though also low because of past disturbance, the probability of biological impacts is greater than at the BEP II location because the alternative site is located on a large parcel of currently vacant land. Implementation of mitigation measures (e.g., site fencing for desert tortoises, surveys for burrowing owl nests, worker education, etc.) would likely reduce any potential biological impacts to less than significant.
- **Visual Resources**: Viewers anticipate open, panoramic views of a predominantly agricultural setting, therefore the addition of prominent geometric forms with significant mass that would interrupt the open expanse and block views of the surrounding hills could be perceived as an adverse visual change. Though the Blythe Airport Site is not co-located with another power plant, such as BEP II, it is farther back from the road and would be less visible to travelers. Mitigation, such as landscaping or power plant color, might reduce impacts to less than significant, although this cannot be determined with certainty without more detailed study and analysis of photosimulations.

INTERSTATE 10 SITE

The Interstate 10 Site was identified by Staff, and is undeveloped agricultural land bordered by West 14th Avenue to the north, the West Side Drain to the west, Seeley Avenue to the south, and Arrowhead Boulevard to the east (see Alternative C on Figure 1). A canal crosses the site between the West Drain and C-05 Canal. A gas compressor station for the SoCalGas pipeline that runs along the south side of I-10 is located across the street to the north of West 14th Avenue. The proposed power plant could most likely connect to this station to receive natural gas. Similar to the proposed project, the I-10 Site would most likely receive its water from groundwater wells. The nearest location to tie into the regional electrical grid would be Western's Blythe Substation, approximately 2.5 miles to the west-northwest.

The County General Plan designation for this land is Industrial, and the County Zoning designation is Medium Manufacturing. The topography of the land is flat bordered by open fields to the south. There are four residences located approximately 0.45 miles west of the site.

Impact Discussion

Following is a discussion of potential environmental impacts at the South of Blythe Site:

- **Air Quality**: This site is located in the MDAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project. Assuming that outstanding issues related to the proposed project are resolved and mitigation measures are developed to reduce proposed project impacts to less-than-significant levels, similar conclusions and measures would apply to this alternative site to reduce air quality impacts to less-than-significant levels.
- **Cultural Resources**: To determine potential impacts of a project, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. However, the I-10 Site would be located on disturbed agricultural land nearby to a gas compressor station and I-10, and without natural waterways or structures, so the potential for significant cultural resources impacts is low.
- **Land Use**: The County General Plan designation for this land is Industrial, and the County Zoning designation is Medium Manufacturing, therefore, a power plant at this site would be consistent with the land use designation. However, the residences to the west of this site and the adjacent gas compressor station may cause significant land use and space constraint issues.
- **Socioeconomics/Environmental Justice**: If this site proposes to use a WCOP, it could have a disproportionately impact on the minority and low-income population of the area. As with the BEP II project, additional information is needed on how the WCOP would be implemented before a conclusion can be made.
- **Transmission System Engineering: This site would require additional linear** facilities to tie into the region's electrical system at Western's Blythe Substation. As with the proposed project, there are similar uncertainties about reliability impacts; therefore, similar impacts would occur and an interconnection study would be necessary before Staff could determine whether system impacts would be less than significant.
- **Traffic and Transportation**: This site is located southeast of the proposed project site and considerably farther from the Blythe Airport, therefore, a power plant at this site would not likely affect airport traffic safety and impacts would be less than significant.

  Water and Soil Resources**:** Similar to the proposed project, water would be supplied via a groundwater well. Similar mitigation measures to those required for the proposed BEP II would be required reduce potential impacts from the WCOP to less than significant. As with the proposed project, the project's use of groundwater at this site would also result in significant impacts. Thus, an alternative cooling technology such as dry or hybrid cooling would likely be required to minimize impacts to groundwater.

- **Noise**: Ambient noise levels in the vicinity are relatively high due to traffic on I-10. However, there are homes located 0.45 miles west of the proposed site that could be impacted by a power plant at this site. The nearest residence to the proposed project is approximately 0.75 miles southwest of the site. Even with the closer proximity of residences, mitigation for plant noise, similar to that recommended at the proposed site, would likely be able to reduce noise impacts to less than significant levels.
- **Hazardous Materials**: Based on the easy truck-route access to I-10, the risk associated with anhydrous ammonia and other hazardous materials would likely be less than those at the proposed site and the other alternatives. However, this site does have residences and a gas compressor station nearby. Mitigation would likely be required for LORS compliance and to ensure that potential impacts would be less than significant.
- **Visual Resources**: The nearby SoCalGas compressor station and the I-10 corridor, and the relatively non-distinct character of the surrounding agricultural lands would likely make visual impacts of a power plant at this site less than significant with mitigation. However, viewer concern is rated moderate, as travelers on I-10 anticipate open, panoramic views of a predominantly non-distinct agricultural setting with the noticeable presence of power transmission and generation facilities. The nearby residents would also be subject to adverse visual change. It is possible that mitigation such as additional landscaping could reduce this impact to less than significant, but this cannot be determined with certainty without more detailed study and analysis of photosimulations.

DEVERS SITE

The Devers Site is located approximately 118 miles west of the proposed site in Riverside County within an area annexed by the City of Palm Springs, approximately eight miles northwest of its center (see Alternative D or Figure 2). The City of Palm Springs has zoned the site Energy/Industrial. The site is currently used for wind generation and is located southwest of Desert Hot Springs, approximately one mile east of State Route 62 (Twentynine Palms Highway), one mile north of I-10, and one to one and a half miles west of Indian Avenue. Dillon Road runs along the south side of the property and the SCE Devers Substation is located to the north. Approximately 0.3 mile from the west border of the Devers Site is Diablo Road and a residential community. There is another residential community 2.5 miles southwest of the site. The surrounding area is dominated by wind turbine generators and transmission lines. The site itself has a level topography. Nine existing wind turbines would have to be removed if this site is used. Independent of use of this alternative site, approximately 90 other wind turbines are undergoing testing for use in Alaska and will be removed by that developer.

The tie into the regional electrical grid would be by building a one mile 230 kV line to the existing SCE Devers Substation, located on a separate parcel 0.6 miles north of the site.

Natural gas would be supplied to the site by a SoCalGas pipeline. SoCalGas has two 30-inch pipelines located approximately two miles from the site along the south side of I-10. This site is located within the Mission Springs Water District (MSWD), a possible provider of reclaimed water via an existing pipeline. Some of the process water could be supplied via on-site groundwater wells drilled into the Garnet Hill Sub-basin and potable water could be supplied from the MSWD by an existing water line at the southern boundary of the site along Dillon Road. However, at this time MSWD does not have an adequate supply of reclaimed water so additional water would have to be imported from an external supply until the facility could expand to meet the increased demand (MSWD 2003).

Impact Discussion

Following is a discussion of potential environmental impacts at the South of Blythe Site:

- **Air Quality**: Unlike the proposed project, this site is located in Salton Sea Air Basin of the South Coast Air Quality Management District (SCAQMD), so potential impacts for particulate matter (PM10) emissions, ozone (from precursor emissions of oxides of nitrogen [NOx] and volatile organic compounds [VOC]), and cost of offsets would be high. More stringent permitting requirements would be implemented and many of the Emissions Reduction Credits (ERCs) that were carried over from BEP I for BEP II would be invalid in the SCAQMD. Despite increased cost, mitigation measures would be necessary to reduce potential impacts to less than significant (e.g., emissions limits, compliance tests, etc.).
- **Cultural Resources**: To determine potential impacts of a project at this site, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. Because the area is already extensively developed for wind energy, it is unlikely that there would be significant impacts to cultural resources.
- **Land Use**: The area surrounding the Devers Site primarily contains the Devers Substation, transmission line right-of-way, wind energy generation, and vacant land. Low density residences are located to the east and west of this site. The site is zoned Energy/Industrial (E-1) but a power plant would not be in compliance with the City of Palm Springs' ordinance, which does not allow for natural gas fueled electrical generation facility usage. Therefore, unless the City Council passed a zoning amendment that would include this use in the zoning code, a plant at this site would be inconsistent with zoning, and, therefore, infeasible.
- **Socioeconomics/Environmental Justice**: An analysis has not been prepared to determine if this alternative could have a disproportionately impact on a minority and low-income population.
- **Transmission System Engineering**: This site would connect to the Devers Substation. One mile of 230 kV transmission line would have to be built across vacant land to the SCE's Devers Substation, approximately 0.6 miles north of the site. Approximately 118 miles of 500 kV transmission line is eliminated. An interconnection study would be necessary before Staff could determine whether system impacts would be less than significant.

- **Traffic and Transportation**: The closest airport is the Palm Springs International Airport, located approximately 6.5 miles to the southeast. Therefore, a power plant at this site would not likely affect airport traffic safety and potential impacts to traffic and transportation would be less than significant.
- **Water and Soil Resources**: Because MSWD does not have an adequate supply of reclaimed water to meet the demand of a power plant at this time, there may not be sufficient water available for use in the proposed wet (evaporative) cooling system. However, if no other adequate supplies of water were identified, dry cooling technology could be used at this site.
- **Biological Resources**: Though the site is already disturbed, there would be potential impacts on the Desert Tortoise, a federally and state listed species, due to nitrogen deposition. Joshua Tree National Park's western border is approximately seven miles east of the Devers Site. The park is heavily air-pollutant impacted and is also Desert Tortoise habitat. Nitrogen deposition from power plant emissions would likely occur in the park (and elsewhere), which would favor non-native, invasive vegetation, which does not provide the same nutritional value as native vegetation. The fire regime could also be impacted. Therefore, detailed biological studies and mitigation measures, such as emissions control, would be necessary to reduce these impacts to less than significant.
- **Geological Resources**: The Banning segment of the San Andreas Fault is located approximately 0.1 mile from the center of the site, and though the project site does not cross the fault, it is located within Seismic Zone 4 of the Uniform Building Code, the highest earthquake hazard zone recognized by the code. Therefore, a plant and the linear facilities would be located within the zone of extreme near-field effects where damage could be excessive in the event of an earthquake. Geotechnical and geological studies and/or changes in plant design (in accordance with the California Building Code) and construction to withstand ground shaking in the event of a major earthquake would be necessary to determine impacts of this alternative site.

NO PROJECT (NO ACTION) ALTERNATIVE

The "no project" alternative under CEQA assumes that the project is not constructed. In the CEQA analysis, the "no project" alternative is compared to the proposed project and determined to be either superior, equivalent, or inferior to it. The CEQA Guidelines state that "the purpose of describing and analyzing a No Project Alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project" (Cal. Code Regs., tit. §15126.6(i)). Toward that end, the "no project" analysis considers "existing conditions" and "what would be reasonably expected to occur in the foreseeable future if the project were not approved…" (§15126.6(e)(2)).

The proposed BEP II would contribute to California's generating resources, increase competition and help form a more reliable electric system that meets the goals of the deregulated energy market. If this facility were not constructed, the proposed site would remain as open space, and additional power to meet both the applicant's objectives and the State's needs would not be available.

Due to market forces, the proposed facility may also serve to replace older, inefficient facilities. If the "no project" alternative were selected, the construction and operational impacts of the BEP II would not occur. The area would remain open and the groundwater would be available for the Colorado River hydrologic recharge system. However, California would not have an additional 520 MW of electrical generation or the benefits noted above.

ALTERNATIVES ELIMINATED FROM DETAILED ANALYSIS

This section describes alternatives that did not satisfy the screening criteria for inclusion in the analysis, and include the following:

- Conservation and demand side management; and
- Renewable resources.

These alternatives, and the reasons they were not considered in detail in this analysis, are described below.

CONSERVATION AND DEMAND SIDE MANAGEMENT

One alternative to a power generation project could consist of a program or programs to reduce energy consumption; the Warren-Alquist Act specifically prohibits the Energy Commission from considering conservation programs as alternatives to a proposed generation project (Pub. Resources Code, Section 25305(c)). This is because the approximate effect of such programs is already accounted for in the agency's "integrated assessment of need," and efficiency or conservation programs would not in themselves be sufficient to substitute for the additional generation calculated to be needed.

In spite of the state's success in reducing demand in 2001, California continues to grow and overall demand is increasing. The 2002-2012 Electricity Outlook Report (CEC 2002c) concludes that, despite exceptional conservation efforts in 2001, voluntary demand reduction will likely decrease over time.

While conservation and demand reduction programs are not considered as alternatives to a proposed project, the Energy Commission is responsible for several such programs, most notably the energy efficiency standards for new buildings and for major appliances. These programs are typically called "energy efficiency," "conservation," or "demand side management" programs. One goal of these programs is to reduce overall electricity use; some programs also aim to shift such energy use to off-peak periods.

The Energy Commission's Energy Efficiency Standards for Residential and Nonresidential Buildings (Title 24, Part 6) were established in 1978 in response to a legislative mandate to reduce California's energy consumption. The standards are updated periodically to allow consideration and possible incorporation of new energy efficiency technologies and methods. The Energy Commission adopted new standards in 2001, as mandated by Assembly Bill 970 to reduce California's electricity demand. The new standards went into effect on June 1, 2001. Since 1975, the displaced peak demand from these conservation efforts has amounted to roughly the equivalent of eighteen 500

MW power plants. The annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more buildings and homes are built under increasingly efficient standards (CEC 2002c).

After the California Independent System Operator (Cal-ISO) ordered rolling blackouts in January 2001 as a result of statewide electricity shortages, conservation efforts initially resulted in dramatic reductions in electricity use. Electricity use for each month in 2001 ranged from 5 percent to 12 percent less than it was in 2000. However, in 2002-2003 demand has been increasing as the memories of rolling blackouts fade.

The California Public Utilities Commission supervises various demand side management programs administered by the regulated utilities, and many municipal electric utilities have their own demand side management programs. The combination of these programs constitutes the most ambitious overall approach to reducing electricity demand administered by any state in the nation.

The Energy Commission is also responsible for determining what the state's energy needs are in the future, using five and 12 year forecasts of both energy supply and demand. The Energy Commission calculates the energy use reduction measures discussed above into these forecasts when determining what future electricity needs are, and how much additional generation will be necessary to satisfy the state's needs.

Having considered all of the demand side management that is "reasonably expected to occur" in its forecasts, the Energy Commission then determines how much electricity is needed. The most recent estimation of electricity needs is found in the 2002-2012 Electricity Outlook Report (available on the Energy Commission's website).

RENEWABLE RESOURCES

Reliance solely on natural gas fired power plants creates both environmental impacts and a dependence on a single energy source. Therefore, renewable resources are attractive power sources.

Staff examined the principal renewable electricity generation technologies that could serve as alternatives to the proposed project and do not burn fossil fuels, and the potential for these facilities to be used instead of the proposed gas-fired plant. These technologies are geothermal, solar, hydroelectric, wind, and biomass. Each of these technologies could be attractive from an environmental perspective because of the absence or reduced level of air pollutant emissions. However, these technologies also can cause environmental impacts and have feasibility problems.

Geothermal. Geothermal technologies use steam or high-temperature water (HTW) obtained from naturally occurring geothermal reservoirs to drive steam turbine/generators. The technology relies on either a vapor dominated resource (dry, super-heated steam) or a liquid-dominated resource to extract energy from the HTW. Geothermal is a commercially available technology, but it is limited to areas where geologic conditions result in high subsurface temperatures. There are no geothermal resources in the project vicinity, making this technology an infeasible alternative.

Biomass. Biomass generation uses a waste vegetation fuel source such as wood chips (the preferred source) or agricultural waste. The fuel is burned to generate steam. Biomass facilities generate substantially greater quantities of air pollutant emissions than natural gas burning facilities, though these emissions may be partially offset by the reduction in emissions from open-field burning of these fields. In addition, biomass plants are typically sized to generate less than 20 MW, which is substantially less than the capacity of the 520 MW BEP II project. In order to generate 520 MW, which is proposed for the BEP II, twenty-six 20 MW biomass facilities would be required. However, these power plants would have potentially significant environmental impacts of their own (CEC 2001a).

Solar. Currently, there are two types of solar generation available: solar thermal power and photovoltaic (PV) power generation.

Solar thermal power generation uses high temperature solar collectors to convert the sun's radiation into heat energy, which is then used to run steam power systems. Solar thermal is suitable for distributed or centralized generation, but requires far more land than conventional natural gas power plants. Solar parabolic trough systems, for instance, use approximately five acres to generate one megawatt.

Photovoltaic (PV) power generation uses special semiconductor panels to directly convert sunlight into electricity. Arrays built from the panels can be mounted on the ground or on buildings, where they can also serve as roofing material. Unless PV systems are constructed as integral parts of buildings, the most efficient PV systems require about four acres of ground area per megawatt of generation.

Solar resources would require large land areas in order to meet the project objective to generate 520 MW of electricity. For example, assuming that a parabolic trough system was located in a maximum solar exposure area, such as in a desert region, generation of 520 MW would require 2,600 acres. For a PV plant, generation of 520 MW would require 2,080 acres.

While solar generation facilities do not generate problematic air emissions and have relatively low water requirements, there are other potential impacts associated with their use. Construction of solar thermal plants can lead to habitat destruction and visual impacts. PV systems can also have negative visual impacts, especially if ground-mounted. Furthermore, PV installations are highly capital intensive, and manufacturing of the panels generates some hazardous wastes.

Both solar thermal and PV facilities generate power during peak usage periods since they collect the sun's radiation during daylight hours. However, even though the use of solar technology may be appropriate for some peaker plants, solar energy technologies cannot provide full-time availability due to the natural intermittent availability of solar resources. Therefore, solar generation technology would not meet the project's goal, which is to provide immediate power to meet demand and generate 520 MW of electricity.

Wind. Wind carries kinetic energy that can be utilized to spin the blades of a wind turbine rotor and an electrical generator, which then feeds alternating current (AC) into the utility grid. Most state-of-the-art wind turbines operating today convert 35 to 40 percent of the wind's kinetic energy into electricity. Modern wind turbines represent viable alternatives to large bulk power fossil power plants as well as small-scale distributed systems. The range of capacity for an individual wind turbine today ranges from 400 watts up to 3.6 MW. California's 1,700 MW of wind power represents 1.5 percent of the state's electrical capacity.

Although air emissions are significantly reduced or eliminated for wind facilities, they can have significant visual effects. Also, wind turbines can cause bird mortality (especially for raptors) resulting from collision with rotating blades.

Wind resources would require large land areas in order to generate 520 MW of electricity. Depending on the size of the wind turbines, wind generation "farms" generally require between 5 and 17 acres to generate one megawatt (resulting in the need for between 2,600 and 8,840 acres to generate 520 MW) (CEC 2001b). California has a diversity of existing and potential wind resource regions that are near load centers such as San Francisco, Los Angeles, San Diego and Sacramento (CEC 2001c). However, wind energy technologies cannot provide full-time availability due to the natural intermittent availability of wind resources. Therefore, wind generation technology would not meet the project's goal, which is to provide immediate power to meet demand and generate 520 MW of electricity.

Hydroelectric Power. While hydropower does not require burning fossil fuels and may be available, this power source can cause significant environmental impacts primarily due to the inundation of many acres of potentially valuable habitat and the interference with fish movements during their life cycles. As a result of these impacts, it is extremely unlikely that new hydropower facilities could be developed and permitted in California within the next several years.

Conclusion Regarding Renewable Resources. The renewable technologies discussed above have the advantage of not requiring the burning of fossil fuels and avoiding the environmental and resource impacts associated with natural gas-fired power. However, these technologies also have the potential to cause significant land use, biological, cultural resource, and visual impacts, and they have substantial cost and regulatory hurdles to overcome before they can provide substantial amounts of power. In summary, Staff has eliminated these alternatives because (a) they cannot feasibly meet project objectives, and (b) they have the potential to create potentially significant environmental effects of their own.

CONCLUSIONS

As determined by Energy Commission Staff, this project as proposed would cause potential impacts in air quality, socioeconomics/environmental justice, land use, cultural resources, water resources, traffic and transportation, and transmission system engineering. For all areas, Staff is recommending measures to mitigate impacts or is waiting for clarification of unresolved issues. Following is a summary of the advantages and disadvantages of the four alternative sites and the no project alternative compared to the proposed project.

South of Blythe Site. This site would have similar impacts to the proposed site in the issue areas of air quality, socioeconomics/environmental justice and water and soil resources. Because it is located farther from the Blythe Airport, this site would be less likely to affect air traffic safety. Like the proposed project, water would be supplied via a groundwater well and thus a WCOP could be implemented, which could result in land management and erosion issues similar to the proposed project. It could have greater impacts on nearby sensitive receptors and the City of Blythe in terms of noise, visual intrusion, and hazardous materials. The high groundwater table in the area, which could cause geological impacts related to liquefaction, and the need to construct separate transmission and natural gas pipelines are also disadvantages of this site. In addition, a transmission study would be required to evaluate impacts on the regional transmission system.

Blythe Airport Site. This site would have similar impacts to the proposed site in the disciplines of air quality, socioeconomics/environmental justice and noise. As at the proposed site, water would be supplied via a groundwater well and thus a WCOP could be implemented, which could result in land management and erosion issues similar to the proposed project. The main disadvantages of this site would be the need to construct additional linear facilities (natural gas pipeline and transmission line) and the proximity of the exhaust stacks to airport operations and higher elevations on the mesa, neither of which are considered to be significant. However, an air traffic safety assessment has yet to be completed. Though this project site is more removed from public view than BEP II, because it is not co-located with another power plant, there would be greater visual impacts than at the proposed site. In addition, a transmission study would be required to evaluate impacts on the regional transmission system.

Interstate 10 Site. This site would have similar impacts to the proposed site in the issue areas of air quality, socioeconomics/environmental justice and water and soil resources. Like the proposed project, water would be supplied via a groundwater well and thus a WCOP could be implemented, which could result in land management and erosion issues similar to the proposed project. Due to the disturbed nature of the land, this site would potentially have fewer impacts than the proposed project for cultural resources at the project site. However, there would be potentially significant impacts associated with hazardous materials, visual resources, noise, traffic and transportation, and land use. In addition, a transmission study would be required to evaluate impacts on the regional transmission system.

Devers Site. The Devers Site is located in an area with industrial and wind farms nearby, therefore, ambient noise levels are already relatively high and a power plant would be consistent with the surrounding environment. Though slightly greater than with the proposed project, construction impacts of additional linears would be minimal. However, there could be potential impacts associated with zoning compliance, air quality in the SCAQMD, biological disturbance due to air pollutants, and geologic resources due to the proximity of the Banning Fault. In addition, the annual availability of 3,300 acre-feet of water for cooling could be a significant issue and the importation of reclaimed water could be prohibitive due both to availability and cost. The use of dry cooling technology could be implemented as an alternative cooling technology option.

In addition, a transmission study would be required to evaluate impacts on the regional transmission system.

No Project. While the impacts of the construction and operation of the proposed project would not occur with the no project alternative, the benefits of the project would also be eliminated. These benefits include the potential for elimination of older, less efficient power plants.

SUMMARY

The Staff Assessment currently finds potential adverse impacts of the proposed project or has outstanding issues in air quality, water and soil resources, cultural resources, traffic and transportation, land use, socioeconomics/environmental justice and transmission systems engineering. However, these impacts would be roughly similar for all of the alternative sites, except the Devers Site, because they are all located in close proximity to one another and within the MDAQMD. The Devers Site, located in the SCAQMD, would have potentially significant air quality impacts as well. In addition, each of the alternative sites has the potential to create other impacts, especially in visual resources, geological resources, land use, biological resources, hazardous materials, and cultural resources, and these issues would require more detailed study. The Devers Site seems to offer the best potential alternative for location and minimizing impacts in most disciplines, however, linear facilities are slightly more extensive and a zoning amendment would be required. In addition, the limited availability of water could require use of alternative cooling technologies, such as dry cooling which is being recommended for the proposed project. The Blythe Airport Site also minimizes impacts in most disciplines and it has similar advantages to the proposed project, however, the need to construct additional linear facilities (natural gas pipeline and transmission line) and the proximity to the airport are disadvantages.

Overall, the four site alternatives considered in this section offer some advantages and disadvantages in comparison to the proposed project. However, none of the alternative sites appear to reduce the potentially significant adverse impacts of the project without causing additional potentially significant impacts themselves. In addition, the construction of BEP II within the boundaries of the BEP I property offers the following advantages: (1) reduction of the need to construct or develop redundant facilities or additional linears; (2) the BEP II power plant would be constructed on land already evaluated and disturbed for the original BEP I, and; (3) co-location would minimize visual impacts. Therefore, the proposed project has an advantage over all of the alternative sites.

REFERENCES

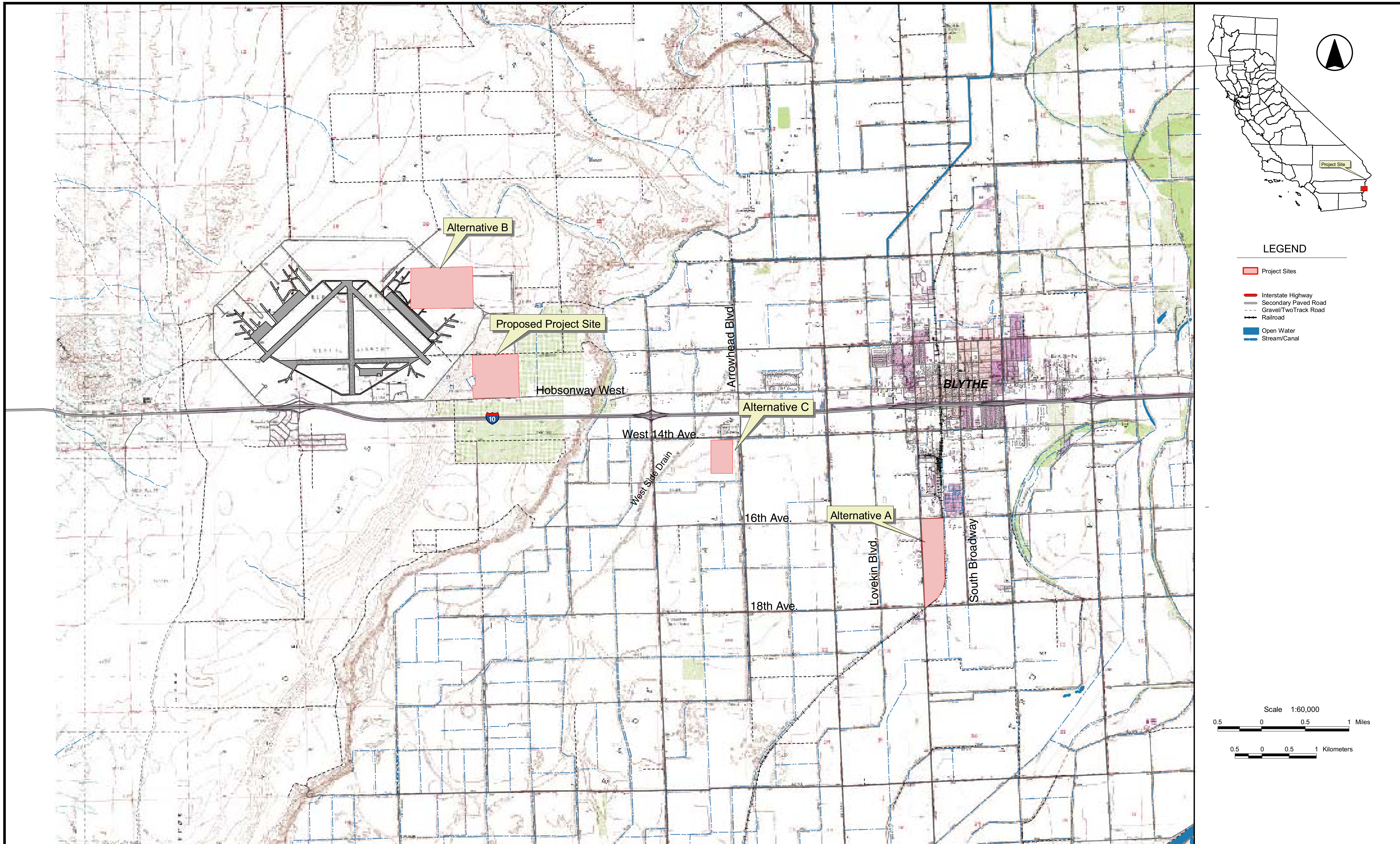
BEP I (Blythe Energy Project). 2000. Final Staff Assessment (99-AFC-2). Submitted to the California Energy Commission on November 15, 2000.

BEP II (Blythe Energy Project, Phase Two). 2002a. Application for Certification, Volume One, Revision One, Blythe Energy Project, Phase Two (02-AFC-1). Dated July 3, 2002.

CEC (California Energy Commission). 2002c. 2002 – 2012 California Electricity Report. February 2002.
____. **2001a.** Internet Website at http://38.144.192.166/development/biomass/biomass.html.
____. **2001b.** Internet Website at http://www.energy.ca.gov/wind/overview.html.
____. **2001c.** Internet Website at http://www.energy.ca.gov/maps/windmap.html
MSWD (Mission Springs Water District). 2003. Phone conversation by Joe Bocanegra, General Manager, with Hedy Born (Aspen Environmental Group), January 7.
OEP (Ocotillo Energy Project). 2001. Application for Certification, Volume One. Submitted to the California Energy Commission, May 2001.

ALTERNATIVES - FIGURE 1

Blythe Energy Project Phase II - Location of Alternative Plant Sites

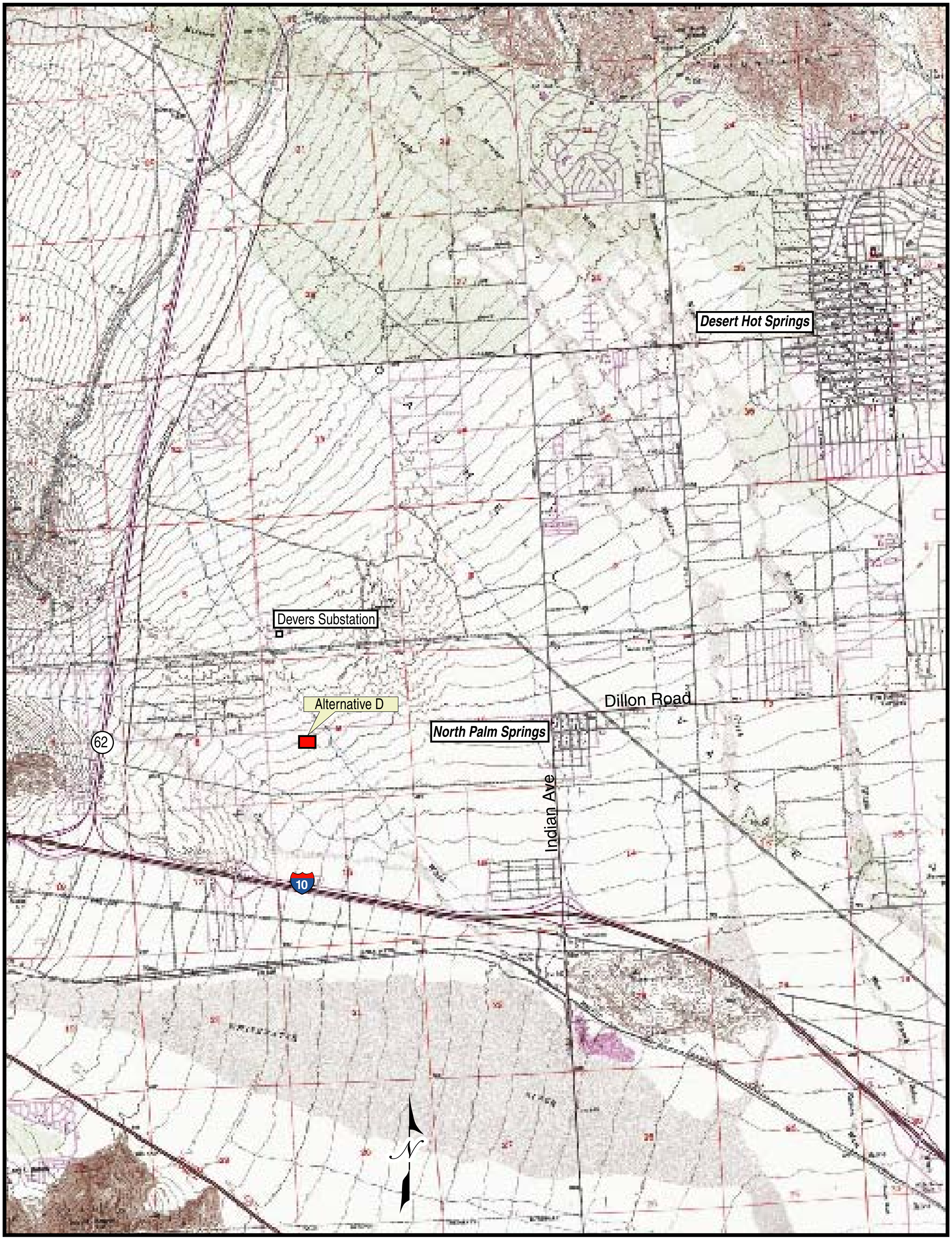


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: AFC Figure 6.0-1

ALTERNATIVES - FIGURE 2

Blythe Energy Project II - Devers Alternative Site Location



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, NOVEMBER 2003

SOURCE: National Geographic TOPO maps

GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

Testimony of Steve Munro

INTRODUCTION

The project General Conditions Including Compliance Monitoring and Closure Plan (Compliance Plan) have been established as required by Public Resources Code section 25532. The plan provides a means for assuring that the facility is constructed, operated and closed in compliance with air and water quality, public health and safety, environmental and other applicable regulations, guidelines, and conditions adopted or established by the California Energy Commission (Energy Commission) and specified in the written decision on the Application for Certification or otherwise required by law.

The Compliance Plan is composed of elements that:

- set forth the duties and responsibilities of the Compliance Project Manager (CPM), the project owner, delegate agencies, and others;
- set forth the requirements for handling confidential records and maintaining the compliance record;
- state procedures for settling disputes and making post-certification changes;
- state the requirements for periodic compliance reports and other administrative procedures that are necessary to verify the compliance status for all Energy Commission approved conditions;
- establish requirements for facility closure plans; and
- specify conditions of certification that follow each technical area that contain the measures required to mitigate any and all potential adverse project impacts associated with construction, operation and closure to an insignificant level. Each specific condition of certification also includes a verification provision that describes the method of assuring that the condition has been satisfied.

GENERAL CONDITIONS OF CERTIFICATION

DEFINITIONS

To ensure consistency, continuity and efficiency, the following terms, as defined, apply to all technical areas, including Conditions of Certification:

<u>SITE MOBILIZATION</u>

Moving trailers and related equipment onto the site, usually accompanied by minor ground disturbance, grading for the trailers and limited vehicle parking, trenching for construction utilities, installing utilities, grading for an access corridor, and other related activities. Ground disturbance, grading, etc. for site mobilization are limited to the portion of the site necessary for placing the trailers and providing access and parking for the occupants. Site mobilization is for temporary facilities and is, therefore, not considered construction.

GROUND DISTURBANCE

Onsite activity that results in the removal of soil or vegetation, boring, trenching, or alteration of the site surface. This does not include driving or parking a passenger vehicle, pickup truck, or other light vehicle, or walking on the site.

GRADING

Onsite activity conducted with earth-moving equipment that results in alteration of the topographical features of the site such as leveling, removal of hills or high spots, or moving of soil from one area to another.

CONSTRUCTION

[From section 25105 of the Warren-Alquist Act.] Onsite work to install permanent equipment or structures for any facility. Construction does **not** include the following:

a. the installation of environmental monitoring equipment;

b. a soil or geological investigation;

c. a topographical survey;

d. any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; or

e. any work to provide access to the site for any of the purposes specified in a., b., c., or d.

START OF COMMERCIAL OPERATION

For compliance monitoring purposes, “commercial operation” is that phase of project development which begins after the completion of start-up and commissioning, where the power plant has reached steady-state production of electricity with reliability at the rated capacity. For example, at the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager.

COMPLIANCE PROJECT MANAGER RESPONSIBILITIES

A Compliance Project Manager (CPM) will oversee the compliance monitoring and shall be responsible for:

1. ensuring that the design, construction, operation, and closure of the project facilities are in compliance with the terms and conditions of the Energy Commission Decision;
2. resolving complaints;
3. processing post-certification changes to the conditions of certification, project description, and ownership or operational control;
4. documenting and tracking compliance filings; and

5. ensuring that the compliance files are maintained and accessible.

The CPM is the contact person for the Energy Commission and will consult with appropriate responsible agencies and the Energy Commission when handling disputes, complaints and amendments.

All project compliance submittals are submitted to the CPM for processing. Where a submittal required by a condition of certification requires CPM approval the approval will involve all appropriate staff and management.

The Energy Commission has established a toll free compliance telephone number of **1-800-858-0784** for the public to contact the Energy Commission about power plant construction or operation-related questions, complaints or concerns.

Pre-Construction and Pre-Operation Compliance Meeting

The CPM may schedule pre-construction and pre-operation compliance meetings prior to the projected start-dates of construction, plant operation, or both. The purpose of these meetings will be to assemble both the Energy Commission's and the project owner's technical staff to review the status of all pre-construction or pre-operation requirements contained in the Energy Commission's conditions of certification to confirm that they have been met, or if they have not been met, to ensure that the proper action is taken. In addition, these meetings shall ensure, to the extent possible, that Energy Commission conditions will not delay the construction and operation of the plant due to oversight and to preclude any last minute, unforeseen issues from arising. Pre-construction meetings held during the certification process must be publicly noticed unless they are confined to administrative issues and processes.

Energy Commission Record

The Energy Commission shall maintain as a public record, in either the Compliance file or Docket file, for the life of the project (or other period as required):

- all documents demonstrating compliance with any legal requirements relating to the construction and operation of the facility;
- all monthly and annual compliance reports filed by the project owner;
- all complaints of noncompliance filed with the Energy Commission; and
- all petitions for project or condition changes and the resulting staff or Energy Commission action.

PROJECT OWNER RESPONSIBILITIES

It is the responsibility of the project owner to ensure that the general compliance conditions and the conditions of certification are satisfied. The general compliance conditions regarding post-certification changes specify measures that the project owner must take when requesting changes in the project design, compliance conditions, or ownership. Failure to comply with any of the conditions of certification or the general compliance conditions may result in reopening of the case and revocation of Energy Commission certification, an administrative fine, or other action as appropriate. A summary of the General Conditions of Certification is included as **Compliance Table 1** at the conclusion of this section. The designation after each of the following summaries of the General Compliance Conditions (**COM-1, COM-2,** etc.) refers to the specific General Compliance Condition contained in **Compliance Table 1.**

COM-1, Unrestricted Access

The CPM, responsible Energy Commission staff, and delegate agencies or consultants, shall be guaranteed and granted unrestricted access to the power plant site, related facilities, project-related staff, and the files and records maintained on site, for the purpose of conducting audits, surveys, inspections, or general site visits. Although the CPM will normally schedule site visits on dates and times agreeable to the project owner, the CPM reserves the right to make unannounced visits at any time.

COM-2, Compliance Record

The project owner shall maintain project files onsite, or at an alternative site approved by the CPM, for the life of the project unless a lesser period of time is specified by the conditions of certification. The files shall contain copies of all "as-built" drawings, all documents submitted as verification for conditions, and all other project-related documents.

COM-3, Compliance Verification Submittals

Each condition of certification is followed by a means of verification. The verification describes the Energy Commission's procedure(s) to ensure post-certification compliance with adopted conditions.

Verification of compliance with the conditions of certification can be accomplished by:

1. reporting on the work done and providing the pertinent documentation in monthly and/or annual compliance reports filed by the project owner or authorized agent as required by the specific conditions of certification;
2. providing appropriate letters from delegate agencies verifying compliance;
3. Energy Commission staff audits of project records; and/or
4. Energy Commission staff inspections of mitigation or other evidence of mitigation.

A cover letter from the project owner or authorized agent is required for all compliance submittals and correspondence pertaining to compliance matters. The cover letter subject line shall identify the involved condition(s) of certification by condition number and include a brief description of the subject of the submittal. The project owner shall also identify those submittals not required by a condition of certification with a statement such as: "This submittal is for information only and is not required by a specific condition of certification." When submitting supplementary or corrected information, the project owner shall reference the date of the previous submittal.

The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether such condition was satisfied by work performed by the project owner or an agent of the project owner.

All submittals shall be addressed as follows:

Steve Munro
Compliance Project Manager
California Energy Commission
1516 Ninth Street (MS-2000)
Sacramento, CA 95814

If the project owner desires Energy Commission staff action by a specific date, they shall so state in their submittal and include a detailed explanation of the effects on the project if this date is not met.

COM-4, Pre-Construction Matrix and Tasks Prior to Start of Construction

Prior to commencing construction a compliance matrix addressing only those conditions that must be fulfilled before the start of construction shall be submitted by the project owner to the CPM. This matrix will be included with the project owner's first compliance submittal, and shall be submitted prior to the first pre-construction meeting, if one is held. It will be in the same format as the compliance matrix referenced below.

Construction shall not commence until the pre-construction matrix is submitted, all pre-construction conditions have been complied with, and the CPM has issued a letter to the project owner authorizing construction. Various lead times (e.g., 30, 60, 90 days) for submittal of compliance verification documents to the CPM for conditions of certification are established to allow sufficient staff time to review and comment and, if necessary, allow the project owner to revise the submittal in a timely manner. This will ensure that project construction may proceed according to schedule.

Failure to submit compliance documents within the specified lead-time may result in delays in authorization to commence various stages of project construction.

Verification lead times (e.g., 90, 60 and 30-days) associated with start of construction may require the project owner to file submittals during the certification process, particularly if construction is planned to commence shortly after certification.
It is important that the project owner understand that the submittal of compliance documents prior to project certification is at the owner's own risk. Any approval by Energy Commission staff is subject to change based upon the Final Decision.

EMPLOYEE ORIENTATION

Environmental awareness orientation and training will be developed for presentation to new employees during project construction as approved by Energy Commission staff and described in the conditions for Biological, Cultural, and Paleontological resources. At the time this training is presented, the project owner's representative shall present information about the role of the Energy Commission's delegate Chief Building Official (CBO) for the project. The role and responsibilities of the CBO to enforce relevant portions of the Energy Commission Decision, the CBSC, and other relevant building and health and safety requirements shall be briefly presented. As part of that presentation, new employees shall be advised of the CBO's authority to halt project construction activities, either partially or totally, or take other corrective measures, as appropriate, if the CBO deems that such action is required to ensure compliance with the Energy Commission Decision, the CBSC, and other relevant building and health and safety requirements. At least 30 days prior to construction, the project owner shall submit the proposed script containing this information for CPM review and approval.

COMPLIANCE REPORTING

There are two different compliance reports that the project owner must submit to assist the CPM in tracking activities and monitoring compliance with the terms and conditions of the Commission Decision. During construction, the project owner or authorized agent will submit Monthly Compliance Reports. During operation, an Annual Compliance Report must be submitted. These reports, and the requirement for an accompanying compliance matrix, are described below. The majority of the conditions of certification require that compliance submittals be submitted to the CPM in the monthly or annual compliance reports.

COM-5, Compliance Matrix

A compliance matrix shall be submitted by the project owner to the CPM along with each monthly and annual compliance report. The compliance matrix is intended to provide the CPM with the current status of all compliance conditions in a spreadsheet format. The compliance matrix must identify:

1. the technical area;
2. the condition number;
3. a brief description of the verification action or submittal required by the condition;
4. the date the submittal is required (e.g., 60 days prior to construction, after final inspection, etc.);
5. the expected or actual submittal date;
6. the date a submittal or action was approved by the Chief Building Official (CBO), CPM, or delegate agency, if applicable;
7. the compliance status of each condition (e.g., “not started,” “in progress” or “completed” (include the date); and
8. the project’s preconstruction and construction milestones, including dates and status (if milestones are required).

Satisfied conditions do not need to be included in the compliance matrix after they have been identified as satisfied in at least one monthly or annual compliance report.

COM-6, Monthly Compliance Report

The first Monthly Compliance Report is due one month following the Energy Commission business meeting date on which the project was approved, unless otherwise agreed to by the CPM. The first Monthly Compliance Report shall include an initial list of dates for each of the events identified on the Key Events List. The Key Events List form is found at the end of this section.

During pre-construction and construction of the project, the project owner or authorized agent shall submit an original and five copies (or amount specified by Compliance Project Manager) of the Monthly Compliance Report within 10 working days after the end of each reporting month. Monthly Compliance Reports shall be clearly identified for the month being reported. The reports shall contain, at a minimum:

1. a summary of the current project construction status, a revised/updated schedule if there are significant delays, and an explanation of any significant changes to the schedule;
2. documents required by specific conditions to be submitted along with the Monthly Compliance Report. Each of these items must be identified in the transmittal letter, and should be submitted as attachments to the Monthly Compliance Report;
3. an initial, and thereafter updated, compliance matrix which shows the status of all conditions of certification;
4. a list of conditions that have been satisfied during the reporting period, and a description or reference to the actions which satisfied the condition;
5. a list of any submittal deadlines that were missed accompanied by an explanation and an estimate of when the information will be provided;
6. a cumulative listing of any approved changes to conditions of certification;
7. a listing of any filings with, or permits issued by, other governmental agencies during the month;
8. a projection of project compliance activities scheduled during the next two months. The project owner shall notify the CPM as soon as any changes are made to the project construction schedule that would affect compliance with conditions of certification;
9. a listing of the month's additions to the on-site compliance file;
10. any requests, with justification, to dispose of items that are required to be maintained in the project owner's compliance file; and
11. a listing of complaints, notices of violation, official warnings, and citations received during the month, a description of the resolutions of any resolved complaints, and the status of any unresolved complaints.

COM-7, Annual Compliance Report

After construction is complete, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports. The reports are for each year of commercial operation and are due to the CPM each year at a date agreed to by the CPM. Annual Compliance Reports shall be submitted over the life of the project unless otherwise specified by the CPM. Each Annual Compliance Report shall identify the reporting period and shall contain the following:

1. 11an updated compliance matrix which shows the status of all conditions of certification (fully satisfied and/or closed conditions do not need to be included in the matrix after they have been reported as closed);
2. a summary of the current project operating status and an explanation of any significant changes to facility operations during the year;

3 documents required by specific conditions to be submitted along with the Annual Compliance Report. Each of these items must be identified in the transmittal letter, and should be submitted as attachments to the Annual Compliance Report;

4 a cumulative listing of all post-certification changes approved by the Energy Commission or cleared by the CPM;

5 an explanation for any submittal deadlines that were missed, accompanied by an estimate of when the information will be provided;

6 a listing of filings made to, or permits issued by, other governmental agencies during the year;

7 a projection of project compliance activities scheduled during the next year;

8 a listing of the year's additions to the on-site compliance file;

9 an evaluation of the on-site contingency plan for unplanned facility closure, including any suggestions necessary for bringing the plan up to date [see General Conditions for Facility Closure addressed later in this section]; and

10 a listing of complaints, notices of violation, official warnings, and citations received during the year, a description of the resolution of any resolved complaints, and the status of any unresolved complaints.

COM-8, Construction and Operation Security Plan

At least 14 days prior to commencing construction, a site-specific Security Plan for the construction phase shall be submitted to the CPM for approval. At least 30 days prior to the initial receipt of hazardous materials on-site, a site-specific Security Plan for the operational phase shall be submitted to the CPM for review and approval.

Construction Security Plan

The Construction Security Plan shall include the following:

1. site fencing enclosing the construction area;
2. use of security guards;
3. check-in procedure or tag system for construction personnel and visitors;
4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency; and
5. evacuation procedures.

Operation Security Plan

1. The Operations Security Plan shall include the following:
2. permanent site fencing and security gate;
3. evacuation procedures;
4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;
5. fire alarm monitoring system;

6. site personnel background checks, including employee and routine on-site contractors [Site personnel background checks are limited to ascertaining that the employee's claims of identity and employment history are accurate. All site personnel background checks shall be consistent with state and federal law regarding security and privacy.];
7. site access for vendors; and
8. requirements for Hazardous Materials vendors to prepare and implement security plans as per 49 CFR 172.800 and to ensure that all hazardous materials drivers are in compliance with personnel background security checks as per 49 CFR Part 1572, Subparts A and B.

In addition, the Security Plan shall include one or more of the following in order to ensure adequate perimeter security:

1. security guards;
2. security alarm for critical structures;
3. perimeter breach detectors and on-site motion detectors; and
4. video or still camera monitoring system.

The Project Owner shall fully implement the security plans and obtain CPM approval of any substantive modifications to the Security Plan. The CPM may authorize modifications to these measures, or may recommend additional measures depending on circumstances unique to the facility, and in response to industry-related security concerns.

COM-9, Confidential Information

Any information that the project owner deems confidential shall be submitted to the Energy Commission's Docket with an application for confidentiality pursuant to Title 20, California Code of Regulations, section 2505(a). Any information, that is determined to be confidential shall be kept confidential as provided for in Title 20, California Code of Regulations, section 2501 et. seq.

COM-10, Department of Fish and Game Filing Fee

Pursuant to the provisions of Fish and Game Code Section 711.4, the project owner shall pay a filing fee in the amount of $850. The payment instrument shall be provided to the Energy Commission's Project Manager (PM), not the CPM, at the time of project certification and shall be made payable to the California Department of Fish and Game. The PM will submit the payment to the Office of Planning and Research at the time of filing of the notice of decision.

COM-11, Reporting of Complaints, Notices, and Citations

Prior to the start of construction, the project owner must send a letter to property owners living within one mile of the project notifying them of a telephone number to contact project representatives with questions, complaints or concerns. If the telephone is not staffed 24 hours per day, it shall include automatic answering with date and time stamp recording. All recorded inquiries shall be responded to within 24 hours. The telephone number shall be posted at the project site and made easily visible to passersby during construction and operation. The telephone number shall be provided to the CPM who will post it on the Energy Commission's web page at:

http://www.energy.ca.gov/sitingcases/power_plants_contacts.html
Any changes to the telephone number shall be submitted immediately to the CPM who will update the web page.

In addition to the monthly and annual compliance reporting requirements described above, the project owner shall report and provide copies of all complaint forms, notices of violation, notices of fines, official warnings, and citations, within 10 days of receipt, to the CPM. Complaints shall be logged and numbered. Noise complaints shall be recorded on the form provided in the **NOISE** conditions of certification. All other complaints shall be recorded on the complaint form (Attachment A).

FACILITY CLOSURE

At some point in the future, the project will cease operation and close down. At that time, it will be necessary to ensure that the closure occurs in such a way that public health and safety and the environment are protected from adverse impacts. Although the project setting for this project does not appear, at this time, to present any special or unusual closure problems, it is impossible to foresee what the situation will be in 30 years or more when the project ceases operation. Therefore, provisions must be made that provide the flexibility to deal with the specific situation and project setting that exist at the time of closure. Laws, Ordinances, Regulations and Standards (LORS) pertaining to facility closure are identified in the sections dealing with each technical area. Facility closure will be consistent with LORS in effect at the time of closure.

There are at least three circumstances in which a facility closure can take place, planned closure, unplanned temporary closure and unplanned permanent closure**.**

CLOSURE DEFINITIONS

Planned Closure

A planned closure occurs at the end of a project's life, when the facility is closed in an anticipated, orderly manner, at the end of its useful economic or mechanical life, or due to gradual obsolescence.

Unplanned Temporary Closure

An unplanned temporary closure occurs when the facility is closed suddenly and/or unexpectedly, on a short-term basis, due to unforeseen circumstances such as a natural disaster or an emergency.

Unplanned Permanent Closure

An unplanned permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly, on a permanent basis. This includes unplanned closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unplanned closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned.

GENERAL CONDITIONS FOR FACILITY CLOSURE

COM-12, Planned Closure

In order to ensure that a planned facility closure does not create adverse impacts, a closure process that provides for careful consideration of available options and applicable laws, ordinances, regulations, standards, and local/regional plans in existence at the time of closure, will be undertaken. To ensure adequate review of a planned project closure, the project owner shall submit a proposed facility closure plan to the Energy Commission for review and approval at least twelve months prior to commencement of closure activities (or other period of time agreed to by the CPM). The project owner shall file 120 copies (or other number of copies agreed upon by the CPM) of a proposed facility closure plan with the Energy Commission.

The plan shall:

1. identify and discuss any impacts and mitigation to address significant adverse impacts associated with proposed closure activities and to address facilities, equipment, or other project related remnants that will remain at the site;
2. identify a schedule of activities for closure of the power plant site, transmission line corridor, and all other appurtenant facilities constructed as part of the project;
3. identify any facilities or equipment intended to remain on site after closure, the reason, and any future use; and
4. address conformance of the plan with all applicable laws, ordinances, regulations, standards, local/regional plans in existence at the time of facility closure, and applicable conditions of certification.

In the event that there are significant issues associated with the proposed facility closure plan's approval, or the desires of local officials or interested parties are inconsistent with the plan, the CPM shall hold one or more workshops and/or the Energy Commission may hold public hearings as part of its approval procedure.

In addition, prior to submittal of the proposed facility closure plan, a meeting shall be held between the project owner and the Energy Commission CPM for the purpose of discussing the specific contents of the plan.

As necessary, prior to or during the closure plan process, the project owner shall take appropriate steps to eliminate any immediate threats to public health and safety and the environment, but shall not commence any other closure activities, until Energy Commission approval of the facility closure plan is obtained.

COM-13, Unplanned Temporary Closure/On-Site Contingency Plan

In order to ensure that public health and safety and the environment are protected in the event of an unplanned temporary facility closure, it is essential to have an on-site contingency plan in place. The on-site contingency plan will help to ensure that all necessary steps to mitigate public health and safety impacts and environmental impacts are taken in a timely manner.

The project owner shall submit an on-site contingency plan for CPM review and approval. The plan shall be submitted no less that 60 days (or other time agreed to by the CPM) prior to commencement of commercial operation. The approved plan must be in place prior to commercial operation of the facility and shall be kept at the site at all times.

The project owner, in consultation with the CPM, will update the on-site contingency plan as necessary. The CPM may require revisions to the on-site contingency plan over the life of the project. In the annual compliance reports submitted to the Energy Commission, the project owner will review the on-site contingency plan, and recommend changes to bring the plan up to date. Any changes to the plan must be approved by the CPM.

The on-site contingency plan shall provide for taking immediate steps to secure the facility from trespassing or encroachment. In addition, for closures of more than 90 days, unless other arrangements are agreed to by the CPM, the plan shall provide for removal of hazardous materials and hazardous wastes, draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. (Also see the analysis for the technical areas of Hazardous Materials Management and Waste Management.)

In addition, consistent with requirements under unplanned permanent closure addressed below, the nature and extent of insurance coverage, and major equipment warranties must also be included in the on-site contingency plan. In addition, the status of the insurance coverage and major equipment warranties must be updated in the annual compliance reports.

In the event of an unplanned temporary closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, or e-mail, within 24 hours and shall take all necessary steps to implement the on-site contingency plan. The project owner shall keep the CPM informed of the circumstances and expected duration of the closure.

If the CPM determines that an unplanned temporary closure is likely to be permanent, or for a duration of more than twelve months, a closure plan consistent with the requirements for a planned closure shall be developed and submitted to the CPM within 90 days of the CPM's determination (or other period of time agreed to by the CPM).

COM-14, Unplanned Permanent Closure/On-Site Contingency Plan

The on-site contingency plan required for unplanned temporary closure shall also cover unplanned permanent facility closure. All of the requirements specified for unplanned temporary closure shall also apply to unplanned permanent closure.

In addition, the on-site contingency plan shall address how the project owner will ensure that all required closure steps will be successfully undertaken in the unlikely event of abandonment.

In the event of an unplanned permanent closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, or e-mail, within 24 hours and shall take all necessary steps to implement the on-site contingency plan. The project owner shall keep the CPM informed of the status of all closure activities.

A closure plan, consistent with the requirements for a planned closure, shall be developed and submitted to the CPM within 90 days of the permanent closure or another period of time agreed to by the CPM.

CBO Delegation and Agency Cooperation

In performing construction monitoring of the project, Commission staff acts as, and has the authority of, the Chief Building Official (CBO). Commission staff may delegate CBO responsibility to either an independent third party contractor or the local building official. Commission staff retains CBO authority when selecting a delegate CBO including enforcing and interpreting state and local codes, and use of discretion, as necessary, in implementing the various codes and standards.

Commission staff may also seek the cooperation of state, regional and local agencies that have an interest in environmental control when conducting project monitoring.

ENFORCEMENT

The Energy Commission's legal authority to enforce the terms and conditions of its Decision is specified in Public Resources Code sections 25534 and 25900. The Energy Commission may amend or revoke the certification for any facility, and may impose a civil penalty for any significant failure to comply with the terms or conditions of the Energy Commission Decision. The specific action and amount of any fines the Energy Commission may impose would take into account the specific circumstances of the incident(s). This would include such factors as the previous compliance history, whether the cause of the incident involves willful disregard of LORS, oversight, unforeseeable events, and other factors the Energy Commission may consider. Moreover, to ensure compliance with the terms and conditions of certification and applicable LORS, delegate agencies are authorized to take any action allowed by law in accordance with their statutory authority, regulations, and administrative procedures.

NONCOMPLIANCE COMPLAINT PROCEDURES

Any person or agency may file a complaint alleging noncompliance with the conditions of certification. Such a complaint will be subject to review by the Energy Commission pursuant to Title 20, California Code of Regulations, section 1230 et seq., but in many instances the noncompliance can be resolved by using the informal dispute resolution process. Both the informal and formal complaint procedure, as described in current State law and regulations, are described below. They shall be followed unless superseded by current law or regulations.

Informal Dispute Resolution Procedure

The following procedure is designed to informally resolve disputes concerning the interpretation of compliance with the requirements of this compliance plan. The project owner, the Energy Commission, or any other party, including members of the public, may initiate this procedure for resolving a dispute. Disputes may pertain to actions or decisions made by any party including the Energy Commission's delegate agents.

This procedure may precede the more formal complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1230 et seq., but is not intended to be a substitute for, or prerequisite to it. This informal procedure may not be used to change the terms and conditions of certification as approved by the Energy Commission, although the agreed upon resolution may result in a project owner, or in some cases the Energy Commission staff, proposing an amendment.

The procedure encourages all parties involved in a dispute to discuss the matter and to reach an agreement resolving the dispute. If a dispute cannot be resolved, then the matter must be referred to the full Energy Commission for consideration via the complaint and investigation process. The procedure for informal dispute resolution is as follows:

Request for Informal Investigation

Any individual, group, or agency may request that the Energy Commission conduct an informal investigation of alleged noncompliance with the Energy Commission's terms and conditions of certification. All requests for informal investigations shall be made to the designated CPM.

Upon receipt of a request for informal investigation, the CPM shall promptly notify the project owner of the allegation by telephone and letter. All known and relevant information of the alleged noncompliance shall be provided to the project owner and to the Energy Commission staff. The CPM will evaluate the request and the information to determine if further investigation is necessary. If the CPM finds that further investigation is necessary, the project owner will be asked to promptly investigate the matter and, within seven working days of the CPM's request, provide a written report of the results of the investigation, including corrective measures proposed or undertaken, to the CPM. Depending on the urgency of the noncompliance matter, the CPM may conduct a site visit and/or request the project owner to provide an initial report, within 48 hours, followed by a written report filed within seven days.

Request for Informal Meeting

In the event that either the party requesting an investigation or the Energy Commission staff is not satisfied with the project owner's report, investigation of the event, or corrective measures undertaken, either party may submit a written request to the CPM for a meeting with the project owner. Such request shall be made within 14 days of the project owner's filing of its written report. Upon receipt of such a request, the CPM shall:

1. immediately schedule a meeting with the requesting party and the project owner, to be held at a mutually convenient time and place;

2. secure the attendance of appropriate Energy Commission staff and staff of any other agencies with expertise in the subject area of concern, as necessary;
3. conduct such meeting in an informal and objective manner so as to encourage the voluntary settlement of the dispute in a fair and equitable manner; and
4. after the conclusion of such a meeting, promptly prepare and distribute copies to all in attendance and to the project file, a summary memorandum which fairly and accurately identifies the positions of all parties and any conclusions reached. If an agreement has not been reached, the CPM shall inform the complainant of the formal complaint process and requirements provided under Title 20, California Code of Regulations, section 1230 et seq.

Formal Dispute Resolution Procedure-Complaints and Investigations

If either the project owner, Energy Commission staff, or the party requesting an investigation is not satisfied with the results of the informal dispute resolution process, such party may file a complaint or a request for an investigation with the Energy Commission's General Counsel. Disputes may pertain to actions or decisions made by any party including the Energy Commission's delegate agents. Requirements for complaint filings and a description of how complaints are processed are in Title 20, California Code of Regulations, section 1230 et seq.

The Chairman, upon receipt of a written request stating the basis of the dispute, may grant a hearing on the matter, consistent with the requirements of noticing provisions. The Energy Commission shall have the authority to consider all relevant facts involved and make any appropriate orders consistent with its jurisdiction (Cal. Code Regs., tit. 20, §§ 1232-1236).

POST CERTIFICATION CHANGES TO THE ENERGY COMMISSION DECISION: AMENDMENTS, OWNERSHIP CHANGES, INSIGNIFICANT PROJECT CHANGES AND VERIFICATION CHANGES

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, in order to modify project design, operation or performance requirements, and to transfer ownership or operational control of the facility.

A petition is required for **amendments** and for **insignificant project changes** as specified below. For verification changes, a letter from the project owner is sufficient. In all cases, the petition or letter requesting a change should be submitted to the CPM, who will file it with the Energy Commission's Docket in accordance with Title 20, California Code of Regulations, section 1209.

The criteria that determine which type of approval process applies are explained below.

AMENDMENT

The project owner shall petition the energy commission, pursuant to Title 20, California Code of Regulations, Section 1769, when proposing modifications to project design, operation, or performance requirements. If a proposed modification results in deletion or change of a condition of certification, or makes changes that would cause the project not to comply with any applicable laws, ordinances, regulations or standards, the petition will be processed as a formal amendment to the final decision, and must be approved by the full commission.

CHANGE OF OWNERSHIP

Change of ownership or operational control also requires that the project owner file a petition, and obtain Commission approval, pursuant to section 1769 (b).

INSIGNIFICANT PROJECT CHANGE

Modifications that do not result in deletions or changes to conditions of certification, and that are compliant with laws, ordinances, regulations and standards may be authorized by the CPM as an insignificant project change pursuant to section 1769(a) (2).

VERIFICATION CHANGE

A VERIFICATION MAY BE MODIFIED BY THE CPM WITHOUT REQUESTING AN AMENDMENT TO THE DECISION IF THE CHANGE DOES NOT CONFLICT WITH THE CONDITIONS OF CERTIFICATION AND PROVIDES AN EFFECTIVE ALTERNATE MEANS OF VERIFICATION.

COM-6, KEY EVENTS LIST

PROJECT: Blythe II Power Project

DOCKET # 02-AFC-1

COMPLIANCE PROJECT MANAGER:

EVENT DESCRIPTION	DATE
Certification Date/Obtain Site Control	
Online Date	
POWER PLANT SITE ACTIVITIES	
Start Site Mobilization	
Start Ground Disturbance	
Start Grading	
Start Construction	
Begin Pouring Major Foundation Concrete	
Begin Installation of Major Equipment	
Completion of Installation of Major Equipment	
First Combustion of Gas Turbine	
Start Commercial Operation	
Complete All Construction	
TRANSMISSION LINE ACTIVITIES	
Start T/L Construction	
SYNCHRONIZATION WITH GRID AND INTERCONNECTION	
COMPLETE T/L CONSTRUCTION	
FUEL SUPPLY LINE ACTIVITIES	
Start Gas Pipeline Construction and Interconnection	
COMPLETE GAS PIPELINE CONSTRUCTION	
WATER SUPPLY LINE ACTIVITIES	
START WATER SUPPLY LINE CONSTRUCTION	
COMPLETE WATER SUPPLY LINE CONSTRUCTION	

TABLE 1
COMPLIANCE SECTION
SUMMARY of GENERAL CONDITIONS OF CERTIFICATION

CONDITION NUMBER	PAGE #	SUBJECT	DESCRIPTION
COM-1	4	Unrestricted Access	The project owner shall grant Energy Commission staff and delegate agencies or consultants unrestricted access to the power plant site.
COM-2	4	Compliance Record	The project owner shall maintain project files on-site. Energy Commission staff and delegate agencies shall be given unrestricted access to the files.
COM-3	4	Compliance Verification Submittals	The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether the condition was satisfied by work performed by the project owner or his agent.
COM-4	5	Pre-construction Matrix and Tasks Prior to Start of Construction	Construction shall not commence until all of the following activities/submittals have been completed: Á property owners living within one mile of the project have been notified of a telephone number to contact for questions, complaints or concerns; Á a pre-construction matrix has been submitted identifying only those conditions that must be fulfilled before the start of construction; Á all pre-construction conditions have been complied with; and Á the CPM has issued a letter to the project owner authorizing construction.
COM-5	6	Compliance Matrix	The project owner shall submit a compliance matrix (in a spreadsheet format) with each monthly and annual compliance report which includes the status of all compliance conditions of certification.
COM-6	6	Monthly Compliance Report (including a Key Events List)	During construction, the project owner shall submit Monthly Compliance Reports (MCRs) which include specific information. The first MCR is due the month following the Commission business meeting date on which the project was approved and shall include an initial list of dates for each of the events identified on the Key Events List.

COM-7	7	Annual Compliance Reports	After construction ends and throughout the life of the project, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports.
COM-8	8	Security Plans	Thirty days prior to commencing construction, the project owner shall submit a Security Plan for the construction phase. Sixty days prior to initial receipt of hazardous material on site, the project owner shall submit an Security Plan & Vulnerability Assessment for the operational phase.
COM-9	9	Confidential Information	Any information the project owner deems confidential shall be submitted to the Dockets Unit with an application for confidentiality.
COM-10	9	Dept of Fish and Game Filing Fee	The project owner shall pay a filing fee of $850 at the time of project certification.
COM-11	9	Reporting of Complaints, Notices and Citations	Within 10 days of receipt, the project owner shall report to the CPM, all notices, complaints, and citations.
COM-12	10	Planned Facility Closure	The project owner shall submit a closure plan to the CPM at least twelve months prior to commencement of a planned closure.
COM-13	11	Unplanned Temporary Facility Closure	To ensure that public health and safety and the environment are protected in the event of an unplanned temporary closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.
COM-14	12	Unplanned Permanent Facility Closure	To ensure that public health and safety and the environment are protected in the event of an unplanned permanent closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.

COMPLAINT REPORT/RESOLUTION FORM

PROJECT NAME: Blythe II Power Project AFC Number: 02-AFC-1C
COMPLAINT LOG NUMBER ____________ Complainant's name and address: Phone number:
Date and time complaint received: Indicate if by telephone or in writing (attach copy if written): Date of first occurrence:
Description of complaint (including dates, frequency, and duration):
Findings of investigation by plant personnel: Indicate if complaint relates to violation of Energy Commission requirement: Date complainant contacted to discuss findings:
Description of corrective measures taken or other complaint resolution: Indicate if complainant agrees with proposed resolution: If not, explain: Other relevant information:
If corrective action necessary, date completed: Date first letter sent to complainant: ____________(copy attached) Date final letter sent to complainant: ____________(copy attached)
This information is certified to be correct. Plant Manager's Signature: ______________________________ Date:

(Attach additional pages and supporting documentation, as required.)

BLYTHE ENERGY PROJECT PHASE II
(02-AFC-1)
PREPARATION TEAM

Executive Summary .... William Pfanner

Introduction .... William Pfanner

Project Description .... William Pfanner

Environmental Assessment

Air Quality .... Brewster Birdsall

Biological Resources .... Natasha Nelson

Cultural Resources .... Gary Reinoehl

Hazardous Materials .... Alvin Greenberg Ph.D. and Rick Tyler

Land Use .... Ken Peterson

Noise and Vibration .... Jim Buntin

Public Health .... Ramesh Sundarewaran

Socioeconomics .... Amanda Stennick

Soil and Water ....Richard Sapuder, Linda Bond, Mark Lindley, and Jim Schoonmaker

Traffic and Transportation .... Ken Peterson

Transmission Line Safety and Nuisance .... Obed Odoemelam, Ph.D.

Visual Resources .... Dale Edwards

Waste Management .... Ramesh Sundarewaran

Worker Safety and Fire Protection .... Alvin Greenberg Ph.D. and Rick Tyler

Engineering Assessment

Facility Design .... Shahab Khoshmashrab, Al McCuen and Steve Baker

Geology, Mineral Resources, and Paleontology .... Patrick A. Pilling, Ph.D., P.E., G.E.

Power Plant Efficiency .... Kevin Robinson and Steve Baker

Power Plant Reliability .... Kevin Robinson and Steve Baker

Transmission System Engineering .... Ajoy Guha, MSEE, P.E. and Al McCuen

Alternatives .... Susan V. Lee

General Conditions .... Steve Munro

Project Assistant .... Evelyn Johnson

Support Staff .... Raquel Rodriguez, and Keith Muntz